AIR QUALITY PERMIT

Issued To: Roundup Power Project
P.O. Box 1697
Helena, Montana 59624

Permit: #3182-00
Application Complete: 07/22/02
Preliminary Determination Issued: 08/12/02
Department Decision Issued: 01/31/03
Permit Issued: 07/21/03
AFS: #065-0003

An air quality permit, with conditions, is hereby granted to the Roundup Power Project (Roundup Power), pursuant to Sections 75-2-204 and 211 of the Montana Code Annotated (MCA), as amended, and Administrative Rules of Montana (ARM) 17.8.701, *et seq.*, as amended, for the following:

SECTION I: Permitted Facilities

A. Permitted Equipment

Roundup Power is proposing to construct and operate a nominal 780-megawatt (MW) pulverized coal (PC)-fired power plant. A complete list of the permitted equipment is contained in the permit analysis.

B. Plant Location

The proposed location for the Roundup Power coal-fired power plant is approximately 12 miles south-southeast of the town of Roundup, Montana. The site is located immediately east of U.S. Route 87, just north of Old Divide Road, and adjacent to the BMP Investments Incorporated coal mine. The legal description of the site is the NW ¼ of the SE ¼ of Section 15, Township 6 North, Range 26 East in Musselshell County.

SECTION II. Conditions and Limitations

A. Operational and Emission Limitations

1. Roundup Power shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

2. Roundup Power shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter (ARM 17.8.308).

3. Roundup Power shall treat all unpaved portions of the haul roads, access roads, parking lots, or general plant area with water and/or chemical dust suppressant as necessary to maintain compliance with the reasonable precautions limitation in Section II.A.2 (ARM 17.8.710).

4. The primary fuel feed rate for each of the two nominal 390-MW PC boilers (main boilers) shall not exceed 1,646,880 tons of coal per rolling 12-month time period (ARM 17.8.710).

5. The annual heat input to each of the main boilers shall not exceed 32,736,120 million British Thermal Units (MMBtu) per rolling 12-month time period (ARM 17.8.710).

6. Oxides of nitrogen (NO_x) emissions from each of the two main boilers shall be controlled with the use of low-NO_x burners, overfire air, and selective catalytic reduction (SCR). NO_x emissions shall not exceed 401.3 lb/hr (0.10 lb/MMBtu) based on a 1-hour average (ARM 17.8.710).

7. NO_x emissions from each of the main boilers shall not exceed 280.9 lb/hr (0.07 lb/MMBtu) based on a rolling 24-hour average (ARM 17.8.715).

8. Roundup Power shall limit the hours of operation, the capacity, the emission rate, and/or the fuel consumption of the two main boilers such that the sum of the NO_x emissions from the two main boilers does not exceed 2,291.5 tons during any rolling 12-month time period. Any calculations used to establish NO_x emissions shall be approved by the Department of Environmental Quality (Department) and shall be based on the NO_x emissions measured by the continuous emission monitor system (CEMS) for each main boiler, unless otherwise allowed by the Department (ARM 17.8.710).

9. Carbon monoxide (CO) emissions from each of the two main boilers shall be controlled by proper boiler design and operation. CO emissions shall not exceed 602.0 lb/hr (0.15 lb/MMBtu) (ARM 17.8.715).

10. Roundup Power shall limit the hours of operation, the capacity, the emission rate, and/or the fuel consumption of the two main boilers such that the sum of the CO emissions from the two main boilers does not exceed 4,910.4 tons during any rolling 12-month time period. Any calculations used to establish CO emissions shall be approved by the Department (ARM 17.8.710).

11. Sulfur dioxide (SO_2) emissions from each of the two main boilers shall be controlled with the use of a dry flue gas desulfurization (FGD) system. SO_2 emissions shall not exceed 602.0 lb/hr (0.15 lb/MMBtu) based on a 1-hour average (ARM 17.8.710).

12. SO_2 emissions from each of the two main boilers shall not exceed 481.6 lb/hr (0.12 lb/MMBtu) based on a rolling 24-hour average (ARM 17.8.715).

13. The control efficiency of the SO_2 emission control equipment, as measured by the inlet SO_2 CEMS (or the "as fired" fuel monitoring system) and the outlet SO_2 CEMS, shall be maintained at a minimum of 90% based on a rolling 30-day average (ARM 17.8.340, ARM 17.8.715, and 40 CFR 60, Subpart Da).

14. Roundup Power shall limit the hours of operation, the capacity, the emission rate, and/or the fuel consumption of the two main boilers such that the sum of the SO_2 emissions from the two main boilers does not exceed 3928.3 tons during any rolling 12-month time period. Any calculations used to establish SO_2 emissions shall be approved by the Department and shall be based on the SO_2 emissions measured by the CEMS for each main boiler, unless otherwise allowed by the Department (ARM 17.8.715).

15. Particulate matter with an aerodynamic diameter less than 10 micrometers (PM_{10}) emissions from each of the two main boilers shall be controlled with the use of a fabric filter baghouse (ARM 17.8.715).

    a. PM_{10} emissions shall not exceed 60.2 lb/hr (0.015 lb/MMBtu) (ARM 17.8.715).

    b. After the first 18 months of operation, Roundup Power shall determine the feasibility of changing the PM_{10} emission limit from 60.2 lb/hr (0.015 lb/MMBtu) to 48.2 lb/hr (0.012 lb/MMBtu). The results of Roundup Power's analysis shall be submitted to the Department no later than 30 days after the first annual PM_{10} source tests (ARM 17.8.715).

16. Roundup Power shall limit the hours of operation, the capacity, the emission rate, and/or the fuel consumption of the two main boilers such that the sum of the PM_{10} emissions from the two main boilers does not exceed 491.0 tons during any rolling 12-month time period. Any calculations used to establish PM_{10} emissions shall be approved by the Department (ARM 17.8.710).

17. Volatile Organic Compound (VOC) emissions from each of the two main boilers shall be controlled by proper boiler design and operation. VOC emissions shall not exceed 12.0 lb/hr (0.0030 lb/MMBtu) (ARM 17.8.715).

18. Roundup Power shall limit the hours of operation, the capacity, the emission rate, and/or the fuel consumption of the two main boilers such that the sum of the VOC emissions from the two main boilers does not exceed 98.2 tons during any rolling 12-month time period. Any calculations used to establish VOC emissions shall be approved by the Department (ARM 17.8.710).

19. Sulfuric Acid (H_2SO_4) Mist emissions from each of the two main boilers shall be controlled with the use of dry FGD. H_2SO_4 emissions shall not exceed 25.7 lb/hr (0.0064 lb/MMBtu) (ARM 17.8.715).

20. The stack height for each of the two main boilers shall, at a minimum, be maintained at 574 feet above ground level (ARM 17.8.710).

21. SO_2 emissions from each of the two auxiliary boilers shall not exceed 6.47 lb/hr (ARM 17.8.715).

22. NO_x emissions from each of the two auxiliary boilers shall be controlled with low-NO_x burners or an equivalent control technology. NO_x emissions shall not exceed 19.8 lb/hr (ARM 17.8.715).

23. CO emissions from each of the two auxiliary boilers shall not exceed 4.12 lb/hr (ARM 17.8.715).

24. The combined diesel consumption of the two auxiliary boilers shall be limited to 2,719,200 gallons per rolling 12-month time period (ARM 17.8.710).

25. The combined hours of operation of the two auxiliary boilers shall be limited to 3300 hours per rolling 12-month time period (ARM 17.8.710).

26. The stack height for each of the two auxiliary boilers shall, at a minimum, be maintained at 259.9 feet above ground level (ARM 17.8.710).

27. The sulfur content of the No. 2 fuel oil used in the auxiliary boilers and the emergency backup generator shall not exceed 0.05% sulfur (ARM 17.8.715).

28. The operation of the emergency backup diesel generator shall not exceed 200 hours per rolling 12-month time period (ARM 17.8.710).

29. Roundup Power shall use any one of the following methods or combination of the following methods to control particulate matter emissions from the coal handling transfer points: dust suppression systems and/or enclosures (ARM 17.8.308 and ARM 17.8.715).

30. Roundup Power shall install, operate, and maintain a bin exhaust filter (VE-15) on the surge hopper of the Crusher House to control the particulate emissions from transfer points #15, #16, and #17 (ARM 17.8.715).

31. Roundup Power shall install, operate, and maintain a baghouse (EP-27) on the Unit #1 Tripper Room Silo Vent to control the emissions from transfer points #20, #21, and #23 (ARM 17.8.715).

32. Roundup Power shall install, operate, and maintain a baghouse (EP-26) on the Unit #2 Tripper Room Silo Vent to control the emissions from transfer points #22, #24, and #25 (ARM 17.8.715).

33. Roundup Power shall install and use a wind fence, use dust suppression sprays, and use pile compaction to control particulate emissions from the inactive storage pile (ARM 17.8.715).

34. Roundup Power shall install and use a wind fence and use dust suppression sprays to control particulate emissions from the active storage pile (ARM 17.8.715).

35. Roundup Power shall handle/transfer all lime using a pneumatic system (ARM 17.8.715).

36. Roundup Power shall install, operate, and maintain a bin exhaust filter to control the particulate emissions from the emission source points for the lime storage silo bin (VE-42) and the lime feed bin (VE-43) (ARM 17.8.715).

37. Roundup Power shall use a vacuum-pressure system to transfer all fly ash (ARM 17.8.715).

38. Roundup Power shall install, operate, and maintain a bin exhaust filter to control the particulate emissions from the emission source points for the fly ash handling system (EP-50, EP-51, EP-52, EP-53, and EP-54) (ARM 17.8.715).

39. All baghouses/bin exhaust filters used to control emissions from coal handling, lime handling, and fly ash handling shall be designed, maintained, and operated such that particulate emissions do not exceed 0.01 gr/dscf (ARM 17.8.715).

40. Roundup Power shall utilize air-cooled condensers (ACC) within the process (ARM 17.8.710).

41. Roundup Power shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 60, Subpart Da (ARM 17.8.340 and 40 CFR 60).

42. Roundup Power shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 60, Subpart Db (ARM 17.8.340 and 40 CFR 60).

43. Roundup Power shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 60, Subpart Y (ARM 17.8.340 and 40 CFR 60).

44. Roundup Power shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements of the Acid Rain Program contained in 40 CFR 72-78 (40 CFR 72 through 40 CFR 78).

45. Roundup Power shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 63, Subpart B (ARM 17.8.341 and 40 CFR 63).

B. Testing Requirements

1. Roundup Power shall use the data from the continuous opacity monitoring system (COMS) to monitor compliance with the opacity limit contained in Section II.A.1, for each of the main boilers (ARM 17.8.710).

2. Roundup Power shall use the data from the NO_x CEMS to monitor compliance with the NO_x emission limits contained in Section II.A.6, Section II.A.7, and Section II.A.8, for each of the main boilers (ARM 17.8.105 and 17.8.710).

3. Roundup Power shall test each of the two main boilers for CO within 180 days of initial start-up of the respective boiler, or according to another testing/monitoring schedule as may be approved by the Department, to monitor compliance with the CO emission limits contained in Section II.A.9. The testing of each boiler shall continue on an annual basis, or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and ARM 17.8.710).

4. Roundup Power shall use the data from the SO_2 CEMS to monitor compliance with the SO_2 emission limits contained in Section II.A.11, Section II.A.12, and Section II.A.14, for each of the main boilers (ARM 17.8.105 and 17.8.710).

5. Roundup Power shall test each of the two main boilers for PM_{10} within 180 days of initial start-up of the respective boiler, or according to another testing/monitoring schedule as may be approved by the Department, to monitor compliance with the PM_{10} emission limit contained in Section II.A.15 and to determine the feasibility of meeting an emission limit based on 0.012 lb/MMBtu. The testing of each boiler shall continue on an annual basis, or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and 17.8.710).

6. Roundup Power shall test each of the two main boilers for H_2SO_4 within 180 days of initial start-up of the respective boiler, or according to another testing/monitoring schedule as may be approved by the Department, to monitor compliance with the H_2SO_4 emission limits contained in Section II.A.19. The testing of each boiler shall continue on an annual basis, or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and ARM 17.8.710).

7. Roundup Power shall test each of the two auxiliary boilers for NO_x and CO, concurrently, within 180 days of initial start-up of the respective boiler, or according to another testing/monitoring schedule as may be approved by the Department, to monitor compliance with the NO_x and CO emission limits contained in Sections II.A.22 and II.A.23. The testing of each boiler shall continue on an every-5-year basis, or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and 17.8.710).

8. Roundup Power shall test each of the two auxiliary boilers for SO_2 within 180 days of initial start-up of the respective boiler, or according to another testing/monitoring schedule as may be approved by the Department, to monitor compliance with the SO_2 emission limit contained in Section II.A.21 (ARM 17.8.105 and 17.8.710).

9. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

10. The Department may require further testing (ARM 17.8.105).

C. Operational Reporting Requirements

1. Roundup Power shall supply the Department with annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the emission inventory contained in the permit analysis.

   Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in the units required by the Department. This information may be used to calculate operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

2. Roundup Power shall notify the Department of any construction or improvement project conducted pursuant to ARM 17.8.705(l)(r), that would include a change in control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emission unit.

   The notice must be submitted to the Department, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information requested in ARM 17.8.705(l)(r)(iv) (ARM 17.8.705).

3. All records compiled in accordance with this permit must be maintained by Roundup Power as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department, and must be submitted to the Department upon request (ARM 17.8.710).

4. Roundup Power shall document, by month, the primary fuel feed rate for each of the two main boilers. By the 25th day of each month, Roundup Power shall total the primary fuel feed rate for each of the boilers during the previous 12 months to verify compliance with the limitation in Section II.A.4. A written report, including the previous 12-month total of the primary fuel feed rate for each of the two main boilers, shall be submitted annually to the Department no later than March 1 and may be submitted along with the annual emission inventory (ARM 17.8.710).

5. Roundup Power shall document, by month, the annual heat input to each of the two main boilers. By the 25th day of each month, Roundup Power shall total the annual heat input to each of the boilers during the previous 12 months to verify compliance with the limitation in Section II.A.5. A written report, including the previous 12-month total of the annual heat input to each of the main boilers, shall be submitted annually to the Department no later than March 1 and may be submitted along with the annual emission inventory (ARM 17.8.710).

6. Roundup Power shall document, by month, the amount of NO_x emissions from the two main boilers. By the 25th day of each month, Roundup Power shall total the NO_x emissions from the two main boilers during the previous 12 months to verify compliance with the limitation in Section II.A.8. A written report, including the previous 12-month total of NO_x emissions from the two main boilers, shall be submitted annually to the Department no later than March 1 and may be submitted along with the annual emission inventory (ARM 17.8.710).

7. Roundup Power shall document, by month, the amount of CO emissions from the two main boilers. By the 25th day of each month, Roundup Power shall total the CO emissions from the two main boilers during the previous 12 months to verify compliance with the limitation in Section II.A.10. A written report, including the previous 12-month total of CO emissions from the two main boilers, shall be submitted annually to the Department no later than March 1 and may be submitted along with the annual emission inventory (ARM 17.8.710).

8. Roundup Power shall document, by rolling 30-day period, the percentage of SO_2 removed from the gas stream by the SO_2 control equipment. By the 25th day of each month, Roundup Power shall calculate the SO_2 removal efficiency during each rolling 30-day period that expired during the previous month to verify compliance with the limitation in Section II.A.13. A written report, including the previous 12 months of rolling 30-day SO_2 removal efficiencies for the two main boilers, shall be submitted annually to the Department no later than March 1 and may be submitted along with the annual emission inventory (ARM 17.8.710).

9. Roundup Power shall document, by month, the amount of SO_2 emissions from the two main boilers. By the 25th day of each month, Roundup Power shall total the SO_2 emissions from the two main boilers during the previous 12 months to verify compliance with the limitation in Section II.A.14. A written report, including the previous 12-month total of SO_2 emissions from the two main boilers, shall be submitted annually to the Department no later than March 1 and may be submitted along with the annual emission inventory (ARM 17.8.710).

10. Within 30 days after conducting the first annual PM_{10} source test, Roundup Power shall submit an analysis of the feasibility of meeting a PM_{10} emission limit of 48.2 lb/hr (0.012 lb/MMBtu). The analysis shall be based on the initial source testing results and the first annual source testing results (ARM 17.8.710).

11. Roundup Power shall document, by month, the amount of PM_{10} emissions from the two main boilers. By the 25th day of each month, Roundup Power shall total the PM_{10} emissions from the two main boilers during the previous 12 months to verify compliance with the limitation in Section II.A.16. A written report, including the previous 12-month total of PM_{10} emissions from the two main boilers, shall be submitted annually to the Department no later than March 1 and may be submitted along with the annual emission inventory (ARM 17.8.710).

12. Roundup Power shall document, by month, the amount of VOC emissions from the two main boilers. By the 25th day of each month, Roundup Power shall total the VOC emissions from the two main boilers during the previous 12 months to verify compliance with the limitation in Section II.A.18. A written report, including the previous 12-month total of VOC emissions from the two main boilers, shall be submitted annually to the Department no later than March 1 and may be submitted along with the annual emission inventory (ARM 17.8.710).

13. Roundup Power shall document, by month, the combined diesel consumption of the two auxiliary boilers. By the 25th day of each month, Roundup Power shall total the combined diesel consumption of the two auxiliary boilers during the previous 12 months to verify compliance with the limitation in Section II.A.24. A written report, including the previous 12-month total of the combined diesel consumption of the two auxiliary boilers, shall be submitted annually to the Department no later than March 1 and may be submitted along with the annual emission inventory (ARM 17.8.710).

14. Roundup Power shall document, by month, the combined hours of operation of the two auxiliary boilers. By the 25th day of each month, Roundup Power shall total the combined hours of operation of the two auxiliary boilers during the previous 12 months to verify compliance with the limitation in Section II.A.25. A written report, including the previous 12-month total of the combined hours of operation of the two auxiliary boilers, shall be submitted annually to the Department no later than March 1 and may be submitted along with the annual emission inventory (ARM 17.8.710).

15. Roundup Power shall document, by month, the sulfur content of the No. 2 fuel oil used in the auxiliary boilers and the emergency backup generator to verify compliance with the limitation in Section II.A.27. A written report, including the previous 12-month summary of the sulfur content of the No. 2 fuel oil, shall be submitted annually to the Department no later than March 1 and may be submitted along with the annual emission inventory (ARM 17.8.710).

16. Roundup Power shall document, by month, the hours of operation of the emergency backup diesel generator. By the 25th day of each month, Roundup Power shall total the hours of operation of the emergency backup diesel generator during the previous 12 months to verify compliance with the limitation in Section II.A.28. A written report, including the previous 12-month total of the hours of operation of the emergency backup diesel generator, shall be submitted annually to the Department no later than March 1 and may be submitted along with the annual emission inventory (ARM 17.8.710).

D. Continuous Monitoring System Requirements

1. Roundup Power shall install, operate, calibrate, and maintain continuous monitoring systems for the following:

   a. A CEMS for the measurement of SO_2 shall be operated on each main boiler stack (ARM 17.8.340; 40 CFR 60, Subpart Da; 40 CFR 60, Subpart Db; and 40 CFR 72-78).

   b. A flow monitoring system to complement the SO_2 monitoring system shall be operated on each main boiler stack (40 CFR 72-78).

   c. A CEMS for the measurement of NO_x shall be operated on each main boiler stack (ARM 17.8.340; 40 CFR 60, Subpart Da; 40 CFR 60, Subpart Db; and 40 CFR 72-78).

   d. A COMS for the measurement of opacity shall be operated on each main boiler stack (ARM 17.8.340; 40 CFR 60, Subpart Da; 40 CFR 60, Subpart Db; and 40 CFR 72-78).

   e. A CEMS for the measurement of oxygen (O_2) or carbon dioxide (CO_2) content shall be operated on each main boiler stack (ARM 17.8.340 and 40 CFR 60, Subpart Da).

   f. A CEMS for the measurement of CO_2 content shall be operated on each main boiler stack (40 CFR 72-78).

2. All continuous monitors required by this permit and by 40 CFR Part 60 shall be operated, excess emissions reported, and performance tests conducted in accordance with the requirements of 40 CFR Part 60, Subpart A; 40 CFR Part 60, Subpart Da; 40 CFR Part 60, Subpart Db; 40 CFR Part 60, Appendix B (Performance Specifications #1, #2, and #3); and 40 CFR Part 72-78, as appropriate (ARM 17.8.340; 40 CFR 60; and 40 CFR 72-78).

3. On-going quality assurance requirements for the gas CEMS must conform to 40 CFR Part 60, Appendix F (ARM 17.8.710).

4. Roundup Power shall inspect and audit the COMS annually, using neutral density filters. Roundup Power shall conduct these audits using the appropriate procedures and forms in the EPA Technical Assistance Document: Performance Audit Procedures for Opacity Monitors (EPA-450/4-92-010, April 1992). The results of these inspections and audits shall be included in the quarterly excess emission report (ARM 17.8.710).

5. Roundup Power shall maintain a file of all measurements from the CEMS, and performance testing measurements; all CEMS performance evaluations; all CEMS or monitoring device calibration checks and audits; adjustments and maintenance performed on these systems or devices, recorded in a permanent form suitable for inspection. The file shall be retained on site for at least 5 years following the date of such measurements and reports. Roundup Power shall supply these records to the Department upon request (ARM 17.8.710).

6. Roundup Power shall maintain a file of all measurements from the COMS, and performance testing measurements; all COMS performance evaluations; all COMS or monitoring device calibration checks and audits; adjustments and maintenance performed on these systems or devices, recorded in a permanent form suitable for inspection. The file shall be retained on site for at least 5 years following the date of such measurements and reports. Roundup Power shall supply these records to the Department upon request (ARM 17.8.710).

E. Notification

1. Roundup Power shall provide the Department (both the Billings regional and Helena offices) with written notification of the following dates within the specified time periods (ARM 17.8.710):

   a. Commencement of construction of the power generation facility within 30 days after commencement of construction;

   b. Anticipated start-up date of the facility postmarked not more than 60 days nor less than 30 days prior to start-up;

   c. Actual start-up date of the first main boiler within 15 days after the actual start-up of the boiler;

   d. Actual start-up date of the second main boiler within 15 days after the actual start-up of the boiler,

   e. All compliance source tests as required by the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106), and

   f. Any malfunction that occurs that can be expected to create emissions in excess of any applicable emission limitations or can be expected to last for a period greater than 4 hours shall be reported to the Department promptly by telephone (ARM 17.8.110).

2. Roundup Power shall provide the Department (both the Billings regional and Helena offices) with written notification of the following items within 30 days after actual startup of the power generation facility, or another time period as may be approved by the Department (ARM 17.8.710):

a. Make, model, type, size, serial number, year of manufacture, and year of installation of all proposed process equipment identified in Section 4.0 of Montana Air Quality Permit Application #3182-00.

b. Make, model, type, size, serial number, year of manufacture, and year of installation of all proposed control equipment identified in Section 5.0 of Montana Air Quality Permit Application #3182-00.

SECTION III: General Conditions

A. Inspection – Roundup Power shall allow the Department's representatives access to the source at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (CEMS, CERMS) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.

B. Waiver – The permit and the terms, conditions, and matters stated herein shall be deemed accepted if Roundup Power fails to appeal as indicated below.

C. Compliance with Statutes and Regulations – Nothing in this permit shall be construed as relieving Roundup Power of the responsibility for complying with any applicable federal or Montana statute, rule or standard, except as specifically provided in ARM 17.8.701, *et seq*. (ARM 17.8.717).

D. Enforcement – Violations of limitations, conditions and requirements contained herein may constitute grounds for permit revocation, penalties or other enforcement action as specified in Section 75-2-401, *et seq*., MCA.

E. Appeals – Any person or persons jointly or severally adversely affected by the Department's decision may request, within 15 days after the Department renders it's decision, upon affidavit setting forth the grounds therefore, a hearing before the Board of Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The Department's decision on the application is not final unless 15 days have elapsed and there is no request for a hearing under this section. The filing of a request for a hearing postpones the effective date of the Department's decision until conclusion of the hearing and issuance of a final decision by the Board.

F. Permit Inspection – As required by ARM 17.8.716, Inspection of Permit, a copy the air quality permit shall be made available for inspection by the Department at the location of the source.

G. Permit Fee – Pursuant to Section 75-2-220, MCA, as amended by the 1991 Legislature, failure to pay the annual operation fee by Roundup Power may be grounds for revocation of this permit, as required by that section and rules adopted thereunder by the Board.

H. Construction Commencement – Construction must begin within 18 months of permit issuance and proceed with due diligence until the project is complete or the permit shall be revoked (ARM 17.8.731).

Attachment 2

INSTRUCTIONS FOR COMPLETING EXCESS EMISSION REPORTS (EER)

PART 1 Complete as shown. Report total time during the reporting period in hours. The determination of plant operating time (in hours) includes time during unit start up, shut down, malfunctions, or whenever pollutants of any magnitude are generated, regardless of unit condition or operating load.

Excess emissions include all time periods when emissions, as measured by the CEMS, exceed any applicable emission standard for any applicable time period.

Percent of time in compliance is to be determined as:

(1 – (total hours of excess emissions during reporting period / total hours of CEMS availability during reporting period)) x 100

PART 2 Complete as shown. Report total time the point source operated during the reporting period in hours. The determination of point source operating time includes time during unit start up, shut down, malfunctions, or whenever pollutants (of any magnitude) are generated, regardless of unit condition or operating load.

Percent of time CEMS was available during point source operation is to be determined as:

(1–(CEMS downtime in hours during the reporting period[a] /total hours of point source operation during reporting period)) x 100

a - All time required for calibration and to perform preventative maintenance must be included in the CEMS downtime.

PART 3 Complete a separate sheet for each pollutant control device. Be specific when identifying control equipment operating parameters. For example: number of TR units, energizers for electrostatic precipitators (ESP); pressure drop and effluent temperature for baghouses; and bypass flows and pH levels for scrubbers. For the initial EER, include a diagram or schematic for each piece of control equipment.

PART 4 Use Table I as a guideline to report <u>all</u> excess emissions. Complete a separate sheet for each monitor. Sequential numbering of each excess emission is recommended. For each excess emission, indicate: 1) time and duration, 2) nature and cause, and 3) action taken to correct the condition of excess emissions. Do not use computer reason codes for corrective actions or nature and cause; rather, be specific in the explanation. If no excess emissions occur during the quarter, it must be so stated.

PART 5 Use Table II as a guideline to report all CEM system upsets or malfunctions. Complete a separate sheet for each monitor. List the time, duration, nature and extent of problems, as well as the action taken to return the CEM system to proper operation. Do not use reason codes for nature, extent or corrective actions. Include normal calibrations and maintenance as prescribed by the monitor manufacturer. Do not include zero and span checks.

PART 6 Complete a separate sheet for each pollutant control device. Use Table III as a guideline to report operating status of control equipment during the excess emission. Follow the number sequence as recommended for excess emissions reporting. Report operating parameters consistent with Part 3, Subpart e.

PART 7 Complete a separate sheet for each monitor. Use Table IV as a guideline to summarize excess emissions and monitor availability.

PART 8 Have the person in charge of the overall system and reporting certify the validity of the report by signing in Part 8.

EXCESS EMISSIONS REPORT

PART 1

a. Emission Reporting Period ______________________________

b. Report Date ______________________________

c. Person Completing Report ______________________________

d. Plant Name ______________________________

e. Plant Location ______________________________

f. Person Responsible for Review and Integrity of Report ______________________________

g. Mailing Address for 1.f. ______________________________

____

h. Phone Number of 1.f. ______________________________

i. Total Time in Reporting Period ______________________________

j. Total Time Plant Operated During Quarter ______________________________

k. Permitted Allowable Emission Rates: Opacity ______________________________

SO_2 ____________ NO_x ____________ TRS ____________

l. Percent of Time Out of Compliance: Opacity ______________________________

SO_2 ____________ NO_x ____________ TRS ____________

m. Amount of Product Produced During Reporting Period ______________________________

n. Amount of Fuel Used During Reporting Period ______________________________

PART 2 - Monitor Information: Complete for each monitor.

a. Monitor Type (circle one)

Opacity SO_2 NO_x O_2 CO_2 TRS Flow

b. Manufacturer ______________________________

c. Model No. ______________________ ______________

d. Serial No. ______________________

e. Automatic Calibration Value: Zero ______________ Span ______________

f. Date of Last Monitor Performance Test ______________________

g. Percent of Time Monitor Available:

1) During reporting period ______________________

2) During plant operation ______________________

h. Monitor Repairs or Replaced Components Which Affected or Altered Calibration Values ______________________

i. Conversion Factor (f-Factor, etc.)

j. Location of monitor (e.g. control equipment outlet)

PART 3 - Parameter Monitor of Process and Control Equipment. (Complete one sheet for each pollutant.)

a. Pollutant (circle one):

Opacity SO_2 NO_x TRS

b. Type of Control Equipment ______________________

c. Control Equipment Operating Parameters (i.e., delta P, scrubber water flow rate, primary and secondary amps, spark rate)

____

d. Date of Control Equipment Performance Test ______________________

e. Control Equipment Operating Parameter During Performance Test

____

____

____

____

PART 4 - Excess Emission (by Pollutant)

Use Table I: Complete table as per instructions. Complete one sheet for each monitor.

PART 5 - Continuous Monitoring System Operation Failures

Use Table II: Complete table as per instructions. Complete one sheet for each monitor.

PART 6 - Control Equipment Operation During Excess Emissions

Use Table III: Complete as per instructions. Complete one sheet for each pollutant control device.

PART 7 - Excess Emissions and CEMS performance Summary Report

Use Table IV: Complete one sheet for each monitor.

PART 8 - Certification for Report Integrity, by person in 1.f.

THIS IS TO CERTIFY THAT, TO THE BEST OF MY KNOWLEDGE, THE INFORMATION PROVIDED IN THE ABOVE REPORT IS COMPLETE AND ACCURATE.

SIGNATURE ________________________________

NAME ________________________________

TITLE ________________________________

DATE ________________________________

TABLE I

EXCESS EMISSIONS

Date	Time From	Time To	Duration	Magnitude	Explanation/Corrective Action

TABLE II

CONTINUOUS MONITORING SYSTEM OPERATION FAILURES

Date	Time From	Time To	Duration	Problem/Corrective Action

TABLE III

CONTROL EQUIPMENT OPERATION DURING EXCESS EMISSIONS

Date	Time From	Time To	Duration	Operating Parameters	Corrective Action

TABLE IV

Excess Emission and CEMS Performance Summary Report

Pollutant (circle one): SO_2 NO_x TRS H_2S CO Opacity

Monitor ID

Emission data summary [1]	**CEMS performance summary** [1]
1. Duration of excess emissions in reporting period due to: a. Startup/shutdown b. Control equipment problems c. Process problems d. Other known causes e. Unknown causes 2. Total duration of excess emissions 3. $\left[\frac{\text{Total duration of excess emissions}}{\text{Total time CEM operated}} \times 100 = \right]$	1. CEMS[2] downtime in reporting due to: a. Monitor equipment malfunctions b. Non-monitor equipment malfunctions c. Quality assurance calibration d. Other known causes e. Unknown causes 2. Total CEMS downtime 3. $\left[\frac{\text{Total CEMS downtime}}{\text{Total time source emitted}} \times 100 = \right]$

[1] For opacity, record all times in minutes. For gases, record all times in hours. Fractions are acceptable (e.g., 4.06 hours)

[2] CEMS downtime shall be regarded as any time CEMS is not measuring emissions.

Permit Analysis
Roundup Power Project
Permit #3182-00

I. Introduction/Process Description

A. Permitted Equipment

The Roundup Power Project (Roundup Power) facility will be located approximately 35 miles north of Billings and 12 miles south-southeast of the town of Roundup. The facility's primary equipment will consist of the following:

- Two coal fired generating units, each with a pulverized coal-fired boiler and a steam turbine-generator with a nominal electrical output of 390-MW (main boilers). Each of the main boilers would be fitted with dry Flue Gas Desulfurization (FGD) systems, Selective Catalytic Reduction (SCR) systems, and pulse jet baghouses. The main boilers will use coal as their primary fuel and No.2 fuel oil for startup.

- Two air-cooled condensers

- Two auxiliary boilers fueled with No.2 fuel oil

- One emergency generator fueled with No.2 fuel oil

- Storage and handling equipment for coal, lime, ash, and No.2 fuel oil

- 4000-foot long overland conveyor

B. Source Description

Coal for the main boilers will be supplied by the BMP Investments Incorporated coal mine that is located on the adjacent property immediately to the east of the power plant location. The coal will be transferred to the power plant via a 4000-foot long overland conveyor. The coal that is transferred to the power plant facility will be stored in either the active coal storage pile or in the inactive coal storage pile. The inactive coal storage pile will consist of approximately 92,500 tons of coal (11 days worth of coal storage for the power plant).

From the 25,000 ton active coal storage pile (Transfer House 1), coal will be transferred to the reclaim hoppers and then on to the crusher house. From the crusher house, coal is transferred via conveyors to the main boilers for combustion.

II. Applicable Rules and Regulations

The following are partial explanations of some applicable rules and regulations that apply to the facility. The complete rules are stated in the Administrative Rules of Montana (ARM) and are available, upon request, from the Department of Environmental Quality (Department). Upon request, the Department will provide references for location of complete copies of all applicable rules and regulations or copies where appropriate.

A. ARM 17.8, Subchapter 1 – General Provisions, including but not limited to:

1. <u>ARM 17.8.101 Definitions</u>. This rule includes a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, provide the facilities and necessary equipment (including instruments and sensing devices) and shall conduct test, emission or ambient, for such periods of time as may be necessary using methods approved by the Department.

   Initial performance tests are required for the main boilers and the auxiliary boilers as directed by the appropriate New Source Performance Standards (NSPS). Continuous emission monitoring systems (CEMS) will be used to monitor ongoing oxides of nitrogen (NO_x) compliance and sulfur dioxide (SO_2) compliance. Continuous opacity monitoring systems (COMS) will be used to monitor ongoing compliance with the opacity limitations. Initial and annual source testing will be used to monitor compliance with the carbon monoxide (CO) and particulate matter with an aerodynamic diameter less than 10 micrometers (PM_{10}) emission limits for the main boilers.

   Initial and every-5-year testing will be used to monitor compliance with the NO_x and CO emission limits for each of the auxiliary boilers. Initial source testing will be used to monitor compliance with the SO_2 emission limit for each of the two auxiliary boilers.

3. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by the Department, any source or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq*., Montana Code Annotated (MCA).

   Roundup Power shall comply with the requirements contained in the Montana Source Test Protocol and Procedures Manual, including, but not limited to, using the proper test methods and supplying the required reports. A copy of the Montana Source Test Protocol and Procedures Manual is available from the Department upon request.

4. ARM 17.8.110 Malfunctions. (2) The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation or to continue for a period greater than 4 hours.

5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means that, without resulting in reduction of the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner as to create a public nuisance.

B. ARM 17.8, Subchapter 2 – Ambient Air Quality, including, but not limited to the following:

1. ARM 17.8.204 Ambient Air Monitoring
2. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
3. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
4. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
5. ARM 17.8.213 Ambient Air Quality Standard for Ozone
6. ARM 17.8.214 Ambient Air Quality Standard for Hydrogen Sulfide
7. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter
8. ARM 17.8.221 Ambient Air Quality Standard for Visibility
9. ARM 17.8.222 Ambient Air Quality Standard for Lead
10. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}

Roundup Power must maintain compliance with the applicable ambient air quality standards.

C. ARM 17.8, Subchapter 3 – Emission Standards, including, but not limited to:

1. ARM 17.8.304 Visible Air Contaminants. This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

2. ARM 17.8.308 Particulate Matter, Airborne. (1) This rule requires an opacity limitation of 20% for all fugitive emission sources and that reasonable precautions be taken to control emissions of airborne particulate matter. (2) Under this rule, Roundup Power shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter.

3. ARM 17.8.309 Particulate Matter, Fuel Burning Equipment. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter caused by the combustion of fuel in excess of the amount determined by this rule.

4. ARM 17.8.310 Particulate Matter, Industrial Process. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter in excess of the amount set forth in this rule.

5. ARM 17.8.322 Sulfur Oxide Emissions--Sulfur in Fuel. (4) Commencing July 1, 1972, no person shall burn liquid or solid fuels containing sulfur in excess of 1 pound of sulfur per million Btu fired. Roundup Power will comply with this rule by combusting low sulfur coal and by applying emission controls for removal of SO_2 from the combustion gases.

6. ARM 17.8.324 Hydrocarbon Emissions--Petroleum Products. (3) No person shall load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank truck or trailer, except through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device as described in (1) of this rule.

7. ARM 17.8.340 Standard of Performance for New Stationary Sources and Emission Guidelines for Existing Sources. This rule incorporates, by reference, 40 CFR 60, Standards of Performance for New Stationary Sources (NSPS). Roundup Power is considered an NSPS affected facility under 40 CFR 60 and is subject to the requirements of the following subparts.

   40 CFR Part 60, Subpart A – General Provisions. This subpart applies to all affected equipment or facilities subject to an NSPS subpart as listed below.

   40 CFR 60, Subpart Da, Standards of Performance Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978. The main boilers at Roundup Power are affected facilities under this subpart because 1) the electric utility steam generating units are capable of combusting more than 73-MW heat input of fossil fuel and 2) the construction of the facility would occur after September 18, 1978.

   40 CFR 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. The auxiliary boilers at Roundup Power are affected facilities under this subpart because 1) the steam generating units will commence construction after June 19, 1984 and 2) the facility will have a heat input capacity from fuels combusted in the steam generating unit of greater than 29 MW. The main boilers are not subject to this subpart because this subpart defines an "affected facility" as a steam generating unit that is not subject to Subpart Da. The main boilers are subject to Subpart Da.

40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation Plants. The coal handling equipment at Roundup Power are affected facilities under this subpart because 1) the equipment (such as breakers and crushers) meets the definition of a coal preparation facility as defined in §60.251 and 2) the facility would process more than 200 tons of coal per day.

8. ARM 17.8.341 Emission Standards for Hazardous Air Pollutants. This source shall comply with the standards and provisions of 40 CFR 61.

9. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. This source, as defined and applied in 40 CFR 63, shall comply with the requirements of 40 CFR 63. Roundup Power is subject to the provisions of 40 CFR 63, Subpart B – Requirements for Control Technology Determinations for Major Sources in Accordance with Clean Air Act Sections, Sections 112(g) and 112(j). Section II.A.45 of this permit identifies the applicable requirement. The Department intends to establish case-by-case MACT limits and to follow the procedures specified in the ARM 17.8.342 and 40 CFR 63 in a process outside of this permit action.

D. ARM 17.8, Subchapter 4 – Stack Height and Dispersion Techniques, including, but not limited to:

1. ARM 17.8.401 Definitions. This rule includes a list of definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.402 Requirements. Roundup Power must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP). Roundup Power made the appropriate demonstration of compliance with the ambient air quality standards.

E. ARM 17.8, Subchapter 5 – Air Quality Permit Application, Operation and Open Burning Fees, including, but not limited to:

1. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an applicant submit an air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to the Department. Roundup Power submitted the appropriate permit application fee for the current permit action.

2. ARM 17.8.505 When Permit Required--Exclusions. An annual air quality operation fee must, as a condition of continued operation, be submitted to the Department by each source of air contaminants holding an air quality permit (excluding an open burning permit) issued by the Department. The air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.

   An air quality operation fee is separate and distinct from an air quality permit application fee. The annual assessment and collection of the air quality operation fee, described above, shall take place on a calendar-year basis. The Department may insert into any final permit issued after the effective date of these rules, such conditions as may be necessary to require the payment of an air quality operation fee on a calendar-year basis, including provisions that prorate the required fee amount.

F. ARM 17.8, Subchapter 7 – Permit, Construction and Operation of Air Contaminant Sources, including, but not limited to:

1. ARM 17.8.701 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.704 General Procedures for Air Quality Preconstruction Permitting. This air quality preconstruction permit contains requirements and conditions applicable to both construction and subsequent use of the permitted equipment.

3. ARM 17.8.705 When Permit Required--Exclusions. This rule requires a facility to obtain an air quality permit or permit alteration if they construct, alter or use any air contaminant sources that have the potential to emit greater than 25 tons per year of any pollutant.

4. ARM 17.8.706 New or Altered Sources and Stacks--Permit Application Requirements. This rule requires that a permit application be submitted prior to installation, alteration or use of a source. Roundup Power submitted the required permit application for the current permit action.

5. ARM 17.8.707 Waivers. ARM 17.8.706 requires that a permit application be submitted 180 days before construction begins. This rule allows the Department to waive this time limit. The Department hereby waives this time limit.

6. ARM 17.8.710 Conditions for Issuance of Permit. This rule requires that Roundup Power demonstrate compliance with applicable rules and standards before a permit can be issued. Also, a permit may be issued with such conditions as are necessary to ensure compliance with all applicable rules and standards. Roundup Power demonstrated compliance with all applicable rules and standards as required for permit issuance.

7. ARM 17.8.715 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that Best Available Control Technology (BACT) shall be utilized. The required BACT analysis is included in Section III of this permit analysis.

8. ARM 17.8.716 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by the Department at the location of the source.

9. ARM 17.8.717 Compliance with Other Statutes and Rules. This rule states that nothing in the permit shall be construed as relieving Roundup Power of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.701, *et seq*.

10. ARM 17.8.720 Public Review of Permit Applications. The rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. Roundup Power submitted an affidavit of publication of public notice for the January 18, 2002, issue of the *Billings Gazette*, a newspaper of general circulation in the city of Billings in Yellowstone County, as proof of compliance with the public notice requirements. Roundup Power submitted a second affidavit of publication of public notice for the January 23, 2002, issue of the *Roundup Record-Tribune* and *The Winnett Times*, newspapers of general circulation in the area of the project, as proof of compliance with the public notice requirements.

11. ARM 17.8.731 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or altered source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued. Roundup Power is required to begin construction within 18 months of permit issuance, or the permit will be revoked.

12. ARM 17.8.733 Modification of Permit. An air quality permit may be modified for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result

in an increase of emissions as a result of those changed conditions. A source may not increase its emissions beyond those found in its permit unless the source applies for and receives another permit.

13. ARM 17.8.734 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of Intent to Transfer, including the names of the transferor and the transferee, is sent to the Department.

G. ARM 17.8, Subchapter 8 – Prevention of Significant Deterioration of Air Quality, including, but not limited to:

1. ARM 17.8.801 Definitions. This rule is a list of applicable definitions used in this subchapter.

2. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications--Source Applicability and Exemptions. The requirements contained in ARM 17.8.819 through ARM 17.8.827 shall apply to any major stationary source and any major modification, with respect to each pollutant subject to regulation under the Federal Clean Air Act (FCAA) that it would emit, except as this subchapter would otherwise allow.

This facility is a listed source because it is a fossil-fuel fired steam-electric plant having more than 250 MMBtu/hr heat input. Furthermore, the facility's emissions are greater than 100 tons per year; therefore, the facility is a major source under the New Source Review (NSR)-Prevention of Significant Deterioration (PSD) program.

H. ARM 17.8, Subchapter 12 – Operating Permit Program Applicability, including, but not limited to:

1. ARM 17.8.1201 Definitions. (23) Major Source under Section 7412 of the FCAA is defined as any source having:

   a. Potential to Emit (PTE) > 100 tons/year of any pollutant;

   b. PTE > 10 tons/year of any one Hazardous Air Pollutant (HAP), PTE > 25 tons/year of a combination of all HAPs, or lesser quantity as the Department may establish by rule; or

   c. PTE > 70 tons/year of PM_{10} in a serious PM_{10} nonattainment area.

2. ARM 17.8.1204 Air Quality Operating Permit Program. (1) Title V of the FCAA amendments of 1990 requires that all sources, as defined in ARM 17.8.1204(1), obtain a Title V Operating Permit. In reviewing and issuing Air Quality Permit #3182-00 for Roundup Power, the following conclusions were made.

   a. The facility's PTE is greater than 100 tons/year for PM_{10}, SO_2, NO_x, and CO.

   b. The facility's PTE is greater than 10 tons/year for an individual HAP and greater than 25 tons/year for the combination of all HAPs.

   c. This source is not located in a serious PM_{10} nonattainment area.

   d. This facility is subject to several current NSPS.

   e. This facility is currently subject to case-by-case MACT (40 CFR 63, Subpart B).

f. This source is a Title IV affected source.

g. This source is not an EPA designated Title V source.

Based on these facts, the Department determined that Roundup Power is a major source of emissions as defined under the Title V Operating Permit Program.

III. BACT Determination

A BACT determination is required for each new or altered source. Roundup Power shall install on the new or altered source the maximum air pollution control capability, which is technically practicable and economically feasible, except that BACT shall be utilized. A "top-down" BACT analysis was submitted by Roundup Power in Permit Application #3182-00, addressing the available methods of controlling emissions from the power plant's main boilers, auxiliary boilers, backup generator, and fugitive emissions. A BACT analysis was conducted for the following main boiler and auxiliary boiler emissions: CO, NO_X, SO_2, PM_{10}, and VOCs. A BACT analysis was also performed for PM_{10} emissions from the fuel handling and storage, lime handling and storage, and ash handling and storage.

The Department reviewed the proposed control methods, previous BACT determinations (via the RACT/BACT/LAER Clearinghouse, federal agency databases, and state agency decisions), and ongoing control proposals (via federal agencies and state agencies), before making the following BACT determination.

A. Main Boilers (MB-1 and MB-2)

1. NO_x Emissions

Two types of control methods exist for NO_x--combustion controls and post-combustion controls. Combustion controls reduce the amount of NO_x that is generated in the boiler, while post-combustion controls remove NO_x from the boiler exhaust gas.

a. Low Excess Air (LEA) - LEA technology is a combustion control. Combustion processes typically require excess air in order to ensure that fuel molecules find and react with oxygen. With LEA, the amount of excess air supplied to the firing chamber is reduced, thereby lowering the combustion temperature. The lower combustion temperature reduces the amount of thermal NO_x formed during the combustion process. Incorporating LEA into boiler design is a technologically feasible option and is common with current boiler design.

b. Low NO_x Burners (LNB) - LNB technology is a combustion control. LNBs limit NO_x formation by controlling both the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. This control is achieved with design features that regulate the aerodynamic distribution and mixing of the fuel and air, yielding reduced oxygen residence time at peak combustion temperatures. The combination of these techniques produces lower NO_x emissions during the combustion process.

c. Overfire Air (OFA) - OFA technology is a combustion control that involves the injection of air into the firing chamber in two staged zones. The staging of the combustion air reduces NO_x formation by two mechanisms. The staged combustion results in a cooler flame, and the staged combustion results in less oxygen reacting with fuel molecules. The degree of staging is limited by operational problems since the staged combustion results in incomplete combustion conditions and a longer flame.

d. Flue Gas Recirculation (FGR) - FGR is a combustion control that controls NO_x by recycling a portion of the flue gas back into the primary combustion zone. The recycled air lowers NO_x emissions by lowering combustion temperatures (the recycled gas is made up of combustion products, which are inert during combustion) and by lowering the oxygen content in the primary flame zone. The amount of recirculation is based on flame stability. The Department was unable to find any examples of FGR being required to control NO_x emissions from other coal-fired boilers.

e. Selective Non-Catalytic Reduction (SNCR) - SNCR is a post-combustion control that involves the direct injection of ammonia or urea at high flue gas temperatures. The ammonia (or urea) reacts with the NO_x in the flue gas to produce N_2 and water. Flue gas temperature at the point of reagent injection can greatly affect NO_x removal efficiencies and the quantity of ammonia or urea that would pass through the SNCR unreacted. If the temperature is too low, NO_x reduction reactions are less effective and ammonia emissions may increase. Conversely, if the temperature is too hot, ammonia is oxidized to NO_x, and the efficiency of NO_x reduction is reduced.

Mixing of the reactant and flue gas within the reaction zone is also an important factor to SNCR performance. In large boilers, the physical distance over which the reagent must be dispersed increases, and the surface area/volume ratio of the convective pass decreases. Both of these factors may make it difficult to achieve good mixing of the reagent and flue gas, to deliver the reagent in the proper temperature window, and to provide sufficient residence time of the reagent and flue gas in that temperature window.

In addition to temperature and mixing, several other factors influence the performance of an SNCR system, including residence time, reagent-to-NO_x ratio, and fuel sulfur content.

Both urea and ammonia-based SNCR systems have been applied to new coal-fired fluidized bed combustion (FBC) boilers. The application of SNCR to FBC boilers is feasible due to the extensive flue gas mixing, which occurs as a result of the fluidizing process. In addition, the normal operating temperature of an FBC is also at the optimum temperature for NO_x reduction by ammonia. On FBCs, SNCR systems have been designed to achieve a NO_x reduction of approximately 30-60%. However, SNCR has not been used on large pulverized coal units. Pulverized coal boilers present several design problems that make it difficult to ensure that the reagent will be injected at the optimum fuel gas temperature, and that there will be adequate mixing and residence time.

f. Selective Catalytic Reduction (SCR) - SCR is a post-combustion control that involves injecting ammonia into the boiler flue gas in the presence of a catalyst to reduce NO_x to N_2 and water. The performance of the SCR is influenced by several factors including flue gas temperature, NO_x level at the SCR inlet, surface area, volume and age of the catalyst, and the amount of ammonia slip that is acceptable.

The optimal temperature range depends on the type of catalyst used, but is typically between 560°F and 800°F to maximize the NO_x reduction efficiency and minimize salt formation. This temperature range typically occurs between the economizer and the air heater in a large utility boiler. Below this range, ammonium sulfate is formed resulting in catalyst deactivation. Above the optimum temperature, the catalyst will sinter and thus deactivate rapidly.

Another factor affecting SCR performance is the condition of the catalyst material. As the catalyst degrades over time or is damaged, NO_x removal decreases.

Based on the inlet NO_x concentration expected for the Roundup Power units, an 80% reduction efficiency would be anticipated using SCR.

The Department determined that a NO_x emission limit of 280.9 lb/hr (0.07 lb/MMBtu) based on a rolling 24-hour period would constitute BACT for each of the main power boilers. The Department also determined that the use of a combination of LNBs, OFA, and SCR technology on each boiler (or an equivalent control technology) capable of maintaining compliance with the NO_x emission limit established through this BACT analysis constitutes BACT. The NOx limit based on 0.07 lb/MMBtu is the lowest emission limit that the Department was able to find for any other comparable source (PC-fired boiler).

2. PM_{10} Emissions

The primary methods for PM_{10} control are post-combustion methods. There are two generally recognized particulate matter control devices that are used to control particulate matter emissions from pulverized coal-fired boilers: electrostatic precipitators (ESP) and fabric filters (or baghouses). Either of these devices, if properly designed and operated, is capable of reducing particulate matter emissions below the 0.03 lb/MMBtu limit required by 40 CFR 60, Subpart Da (NSPS) as well as limiting opacity to below 20%.

For this BACT analysis, and for permitting purposes, uncontrolled particulate matter emissions from the proposed boiler were calculated based on the following assumptions: (1) 80% of the ash would be emitted as fly ash; (2) all fly ash would be emitted as filterable particulate matter; and (3) all filterable particulate matter would be classified as PM_{10}. Assuming a maximum coal ash content of 10.12% and a heating value of 9,916 Btu/lb, the maximum uncontrolled PM_{10} emissions from the boiler would be 8.16 lb/MMBtu. This will be used as the baseline PM_{10} emission rate for this BACT analysis.

a. ESP - Electrostatic precipitation technology is applicable to a variety of coal combustion sources. ESPs remove particulate matter from the flue gas stream by charging fly ash particulates with a high direct current (dc) voltage and attracting these particles to charged collection plates. A layer of collected particulate forms on the collecting plates (electrodes) and is removed by rapping the electrodes. The collected particulate drops into hoppers below the precipitator and is periodically removed from the fly ash handling system.

Because of their modular design, ESPs can be applied to a wide range of system sizes and would have no adverse effect on combustion system performance. The operating parameters that influence ESP performance include fly ash mass loading, particle size distribution, fly ash electrical resistivity, and precipitator voltage and current. Other factors that determine ESP collection efficiency are collection plate area, gas flow velocity, and cleaning cycle. Data for ESPs applied to coal-fired sources show fractional collection efficiencies of approximately 95% for fine particles (less than 0.1 microns) and greater than 99% for coarse particles (greater than 10 microns). These data show a reduction in collection efficiency for particle diameters between 0.1 and 10 micrometers.

ESPs are considered a technically feasible option for Roundup Power.

b. Fabric Filters - Fabric filtration has been widely applied to coal combustion sources and consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure incorporating dust hoppers. Fabric filters use fabric bags as filters to collect particulate matter. The particulate-laden gas enters a fabric filter compartment and passes through a layer of filter bags. The collected particulate forms a cake on the bag that enhances the bag's filtering efficiency. Excessive caking would increase the pressure drop across the fabric filter at which point the filters must be cleaned.

The particulate removal efficiency of fabric filters is dependent upon a variety of particle and operational characteristics. Particle characteristics that affect the collection efficiency include particle size distribution, particle cohesion characteristics, and particle electrical resistivity. Operational parameters that may affect fabric filter collection efficiency include bag material, air-to-cloth ratio, and operating pressure loss. In addition, certain filter properties (e.g., structure of the fabric and fiber composition) can affect the system's particle collection efficiency.

Fabric filters are considered a technically feasible option to control particulate matter from the proposed boilers. Fabric filters are capable of collection efficiencies greater than 99% when appropriately sized and operated.

Upon review of other BACT determinations for PM_{10} emissions from pulverized coal fired boilers, the Department determined that a PM_{10} emission limit of 60.2 lb/hr (0.015 lb/MMBtu) constitutes BACT for each of the main power boilers. The Department also determined that the use of a fabric filter baghouse (or an equivalent control technology) capable of maintaining compliance with the PM_{10} emission limit would constitute BACT. The Department considered an emission limit of 48.2 lb/hr (0.012 lb/MMBtu) as BACT. However, the technical feasibility of Roundup Power complying with such a limit was questionable. Therefore, the Department established an emission limit of 60.2 lb/hr (0.015 lb/MMBtu). The initial and first annual PM_{10} testing required of Roundup Power will be used to determine whether or not the PM_{10} emission limit should be lowered. After an 18-month "evaluation period," the Department will determine the feasibility of lowering the PM_{10} limit.

3. SO_2 Emissions

SO_x emissions from coal combustion consist primarily of SO_2 with a much lower quantity of SO_3 and gaseous sulfates. These compounds form as the organic and pyretic sulfur in the coal is oxidized during the combustion process. On average, about 95% of the sulfur present in bituminous coal will be emitted as gaseous SO_x. Boiler size, firing configuration, and boiler operations generally have little effect on the percent conversion of fuel sulfur to SO_2.

The generation of SO_2 is directly related to the sulfur content and heating value of the fuel burned. The sulfur content and heating value of coal can vary dramatically depending on the source of the coal. Roundup Power would be a mine-mouth facility and would receive coal from the BMP Investments Incorporated coal mine located adjacent to the proposed power plant.

Based on an analysis of the average quality coal sample obtained from BMP Investments Incorporated, the average heating value of coal would be approximately 9,232 Btu/lb, and the average sulfur content is expected to be 1.00%. Without post-combustion controls, maximum SO_2 emissions from the boiler firing this coal would be 2.17 lb/MMBtu. This emission rate was considered as the baseline emission rate for this BACT analysis.

Several techniques are used to reduce SO_2 emissions from coal combustion. Specific to Roundup Power, both CFB and IGCC technologies were reviewed initially in the permitting process. CFBs are better suited to poor quality fuel (such as high sulfur/low heating value coal or coal mine waste). IGCC would involve re-defining the project. In addition, IGCC is not a well-established technology. The Department was unable to find any examples of a regulating agency redefining a proposed PC-fired boiler project with an IGCC, as part of a BACT determination. PC-fired boilers are normally used with a high quality fuel (such as the coal from the Bull Mountain Mine, as proposed by Roundup Power). Although IGCC and CFB may achieve a slightly lower SO_2 emissions rate than a PC-fired boiler, the reduction in emissions would be largely offset by the additional fuel that would have to be burned in order to produce the same net power output. Therefore, the BACT analysis focused on the PC-fired boiler.

Viable strategies for the control of SO_2 emissions can be divided into pre-combustion and post-combustion categories. A pre-combustion method is to switch to lower sulfur coals, since SO_2 emissions are proportional to the sulfur content of the coal. Post-combustion flue gas desulfurization (FGD) techniques can remove SO_2 formed during combustion.

a. Fuel Switching – A potential control for reducing SO_2 emissions from the proposed project is reducing the amount of sulfur contained in the coal. According to Roundup Power, main boilers are designed to burn local coal from the BMP Investments Incorporated coal mine. The coal is a bituminous western coal with a relatively high heat content and low sulfur content. Bituminous coals from mines in the eastern and midwestern U.S. generally have a higher heating value, but also have a significantly higher sulfur content. Western sub-bituminous coals may have a somewhat lower average sulfur content but also typically have lower heating values.

   Roundup Power is designed as a mine-mouth project. Requiring that Roundup Power import other coal to this facility would be an economically infeasible option. Furthermore, although burning western sub-bituminous coal may reduce the uncontrolled SO_2 emission rate somewhat, the controlled SO_2 emission rate would be essentially the same for either sub-bituminous coal or BMP Investments Incorporated coal. Overall, there is no justification, either economically or environmentally, to require Roundup Power to import a coal with a lower sulfur content.

b. Fuel Blending - Another potential way of reducing SO_2 emissions from the proposed project would be to blend the Bull Mountain coal with another coal source of lower sulfur content. However, since the Roundup Power boilers are designed to burn local coal from the BMP Investments Incorporated coal mine, the economics of fuel blending would be infeasible. Furthermore, since the control technologies are designed to provide a certain maximum control value (0.12 lb/MMBtu for example), the controlled SO_2 emission rate would be essentially the same for either BMP Investments Incorporated coal or BMP Investments Incorporated coal blended with another coal source. Overall, there is no justification, either economically or environmentally, to require Roundup Power to use a coal with a lower sulfur content.

   Beyond the fact that the controlled emissions would remain unchanged from such fuel blending, the process of transporting lower sulfur coal from another area would create negative collateral environmental impacts, such as increased diesel consumption to transport the coal to the project site by train, increased opportunity for an accident in carrying the fuel to the project site, etc.

c. Wet Scrubbing (Lime/Limestone) - Wet FGD technology is an established SO_2 control technology. Wet FGD systems are generally categorized as lime or limestone scrubbing systems. The scrubbing process and equipment for both lime scrubbing and limestone scrubbing is similar. Some FGD systems are designed to accommodate both lime and limestone.

i. Wet Lime Scrubbing - The wet lime scrubbing process uses an alkaline slurry made by adding lime (CaO) to water. The alkaline slurry is sprayed in the absorber and reacts with SO_2 in the flue gas. Insoluble calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) salts are formed in the chemical reaction that occurs in the scrubber. The salts are removed as a solid waste by-product. The waste by-product is made up of mainly $CaSO_3$, which is difficult to dewater. Solid waste by-products from wet lime scrubbing are typically managed in dewatering ponds and landfills.

ii. Wet Limestone Scrubbing - Limestone scrubbers are very similar to lime scrubbers. However, the use of limestone ($CaCO_3$) instead of lime requires different feed preparation equipment and a higher liquid-to-gas ratio. The higher liquid-to-gas ratio typically requires a larger absorbing unit. The limestone slurry process also requires a ball mill to crush the limestone feed.

Forced oxidation of the scrubber slurry can be used with either the lime or limestone wet FGD system to produce gypsum solids instead of the calcium sulfite by-product. Forced oxidation of the scrubber slurry provides a more stable by-product and reduces the potential for scaling in the FGD. The gypsum by-product may be salable, reducing the quantity of solid waste that needs to be landfilled.

Wet lime/limestone scrubber systems can achieve SO_2 control efficiencies of greater than 95% when used for boilers burning higher sulfur bituminous coals. The actual control efficiency of a wet FGD system depends on several factors, including the uncontrolled SO_2 concentration entering the system.

Wet FGD is considered a technically feasible control option for this project. For this BACT analysis, it was assumed that the wet FGD system would consist of wet limestone scrubbing with forced oxidation. Wet lime and wet limestone scrubbing systems achieve about the same SO_2 control efficiency, however, the higher cost of lime makes wet limestone scrubbing the more economically feasible option of the two.

Using a maximum uncontrolled SO_2 emission rate of 2.17 lb/MMBtu, the wet limestone scrubbing system could consistently achieve 96% SO_2 removal, resulting in a controlled emission rate of 0.08 lb/MMBtu.

iii. Wet FGD with Wet Electrostatic Precipitator (WESP) - Wet FGD systems can result in increased emissions of condensable particulates and acid gases. Additional add-on technology (such as WESP) exists to address the particulate and acid gas concern associated with wet FGD. WESP operates in much the same way as a dry ESP; charging and collecting the fine particulates. However, with WESP, the cleaning is performed by washing the collection surfaces with water rather than cleaning by mechanical means.

Wet FGD combined with WESP (wet FGD+WESP) is considered a technically feasible option to control SO_2 and acid gases from the proposed facility. The major advantage of using this combined technology instead of wet FGD alone is the reduction of sulfuric acid mist. It is anticipated that the SO_2 emission rate would still be approximately 0.08 lb/MMBtu; however, the collateral environmental impact of the control system would be reduced. However, the cost per ton of reduction would increase.

iv. Dual-Alkali Wet Scrubber - Dual-alkali scrubbing is a desulfurization process that uses a sodium-based alkali solution to remove SO_2 from combustion exhaust gas. The process uses both sodium-based and calcium-based compounds. The sodium-based reagent absorbs SO_2 from the exhaust gas, and the calcium-based solution (lime or limestone) regenerates the spent liquor. Calcium sulfites and sulfates are precipitated and discarded as sludge, while the regenerated sodium solution is returned to the absorber loop.

The dual-alkali process requires lower liquid-to-gas ratios than scrubbing with lime or limestone. The reduced liquid-to-gas ratios generally mean smaller reaction units, however additional regeneration and sludge processing equipment is necessary.

The sodium-based scrubbing liquor, typically consisting of a mixture of sodium hydroxide, sodium carbonate, and sodium sulfite, is an efficient SO_2 control reagent. However, the high cost of the sodium-based chemicals limits the feasibility of such a unit on a large utility boiler. In addition, the process generates a less stable sludge that can create material handling and disposal problems.

The total water use demands for a wet FGD system (for two 390-MW units) would be approximately 420.5 MMgal/year, the total sorbent feed rate for a wet FGD system would be approximately 24,740 lb/hr, and the total solid waste generation rate would be approximately 206,296 ton/yr. In addition, the use of a wet FGD system by Roundup Power would result in approximately 35 gal/min of wastewater. Treatment of the wastewater may require settling, pH adjustment, desupersaturation, and chemical precipitation.

Wet FGD provides some control of H_2SO_4 emissions. The total emissions (from both units) of H_2SO_4 while using wet FGD would be approximately 1,254 tons per year. If wet FGD was used in conjunction with WESP, the total H_2SO_4 emissions would be 125 tons per year.

The use of wet FGD would potentially result in visibility impacts both locally and on a more widespread basis. Locally, the high moisture plume would be quite visible on days with cool weather or humid conditions.

The average cost per ton of reduction was determined for wet FGD and wet FGD+WESP. For wet FGD, the average cost per ton of reduction was estimated to be \$435 and for wet FGD+WESP, the average cost per ton of reduction was estimated to be \$542.

d. Dry Flue Gas Desulfurization - An alternative to wet scrubbing that effectively removes SO_2 from combustion gases is dry scrubbing. Dry FGD systems produce a dry by-product that is removed in the particulate control equipment, versus wet FGD systems where the by-product is a slurry collected separately from the fly ash. Various types of dry FGD systems are described below.

i. Spray Dry Absorber - The typical spray dry absorber uses a slurry of lime and water injected into the tower to remove SO_2 from the combustion gases. The towers must be designed to provide adequate contact and residence time between the exhaust gas and the slurry in order to produce a relatively dry by-product. The process equipment associated with a spray dryer typically includes an alkaline storage tank, mixing and feed tanks, an atomizer, spray chamber, particulate control device, and a recycle system. The recycle system collects solid reaction products and recycles them back to the spray dryer feed system to reduce alkaline sorbent use.

   Spray dry systems are the typical dry scrubbing method in large industrial and utility boiler applications. Spray dry systems have demonstrated the ability to achieve greater than 90% SO_2 reduction on a consistent basis. The actual control efficiency depends on several factors, including the SO_2 concentration in the flue gas exhaust entering the spray dryer. Based on a maximum uncontrolled SO_2 emission rate of 2.17 lb/MMBtu, the dry spray absorber technology would consistently achieve a removal efficiency of approximately 94%.

ii. Dry Sorbent Injection - Dry sorbent injection involves the injection of powdered absorbent directly into the flue gas exhaust stream. Dry sorbent injection systems are simple systems, and generally require a sorbent storage tank, feeding mechanism, transfer line and blower, and an injection device. The dry sorbent is typically injected countercurrent to the gas flow. An expansion chamber is often located downstream of the injection point to increase residence time and efficiency. Particulates generated in the reaction are controlled in the systems particulate control device.

   Typical SO_2 control efficiencies for a dry sorbent injection system are approximately 50%. The control efficiency of the dry sorbent system is lower than the control efficiency of either the wet FGD or spray dry absorber FGD.

iii. Circulating Dry Scrubber - A third type of dry scrubbing system uses a circulating fluidized bed of dry hydrated lime reagent to remove SO_2. Flue gas passes through a venturi at the base of a vertical reactor tower and is humidified by a water mist. The humidified flue gas then enters a fluidized bed of powdered hydrated lime where SO_2 is removed. The dry by-product produced by this system is similar to the spray dry absorber by-product and is routed with the flue gas to the particulate removal system. Because of the high particulate loading, the pressure drop across a fabric filter is generally unacceptable; therefore, ESPs are generally required for particulate control.

   The circulating dry scrubber has limited application and has not been used on large pulverized coal boilers. Assuming that a circulating dry scrubber system could be designed for the proposed project, the anticipated SO_2 control efficiency would be similar to the control efficiency of a spray dry absorber system.

The total water use demands for a dry FGD system (for two 390-MW units) would be approximately 304.8 MMgal/year, the total sorbent feed rate for a dry FGD system would be approximately 20,664 lb/hr, and the total solid waste generation rate would be approximately 154,458 ton/yr. In addition, the dry FGD system would not generate a wastewater stream. The dry by-product that is created in a dry FGD system does not require dewatering or treatment prior to disposal.

Dry FGD also provides control of H_2SO_4 emissions. The total emissions (from both units) of H_2SO_4 while using dry FGD would be approximately 209 tons per year.

The use of dry FGD would potentially result in visibility impacts on a more widespread basis, but would likely not result in impacts on a local basis. On a more widespread basis, the facility's modeled emissions indicate that impacts may result at Class I areas around the facility. Locally, the plume would be relatively dry and would not be much more visible on any one day as compared to another.

The average cost per ton of reduction was determined for dry FGD. The average cost per ton of reduction was estimated to be $390.

The Department determined that wet scrubbing does not constitute BACT for the main power boiler for a variety of reasons. Although wet lime and wet limestone scrubbing are technically feasible, the technologies can result in collateral environmental impacts. For example, both of these technologies can result in the formation of condensable particulates and acid gases, neither of which would be controlled with the proposed particulate control (baghouse). In addition, the wet process would require additional water, which is a critical limiting factor in the area. In fact, an air cooled condenser (ACC) will be used elsewhere in the process, rather than a cooling tower, to minimize water usage. Also, the solid waste by-product from the scrubbing process would need to be managed in dewatering ponds and/or a landfill. Conversely, the Department determined that the control provided by a dry FGD system is consistent with other recently permitted similar sources and that the collateral environmental effects from using a wet FGD system are too great to justify designating that a wet FGD (with or without WESP) system constitutes BACT.

The Department investigated the sulfur percentage of the Bull Mountain coal (≈1.00%) in comparison with the sulfur percentage of the coal for other recently permitted similar sources. Based upon this comparison, the Department determined that an SO_2 emission limit of 481.6 lb/hr (0.12 lb/MMBtu) based upon a rolling 24-hour average and a minimum control efficiency of 90% will constitute BACT for each of the two main boilers. The sulfur content of the Bull Mountain coal equates to approximately 2.17 lb/MMBtu of uncontrolled SO_2 emissions. The SO_2 BACT limitation will require that Roundup Power meet a design efficiency of ≈94.5% while burning 1.0% sulfur coal. Such a design efficiency is consistent with other recently permitted similar sources. The rolling 30-day SO_2 control efficiency of the SO_2 control device will be limited to 90% or greater. The Department also determined that the use of a dry FGD (or an equivalent control technology) capable of maintaining compliance with the SO_2 emission limit would constitute BACT.

4. CO Emissions

CO is a product of incomplete combustion. In order to minimize emissions of CO, good combustion must be ensured. An ideal burner scenario designed for complete combustion would allow for maximum temperatures, maximum residence time, and enough excess air and turbulence to assure good mixing and availability of O_2. However, CO emissions vary inversely with NO_x emissions. Combustion controls designed to reduce NO_x emissions, including low excess air, reduced residence time, and lower temperatures, tend to increase the generation of CO.

Two post-combustion control systems have been identified for potential application at the proposed Roundup Power facility; thermal oxidation and catalytic oxidation. Both of these post-combustion control systems are currently used to control volatile organic compound emissions from sources in petro-chemical industry.

a. Catalytic Oxidation - Catalytic oxidation systems are designed to oxidize CO to CO_2 in the presence of a catalyst. In refinery applications and on gas turbine applications, catalytic oxidation systems have demonstrated CO reduction efficiencies of 80-90%. However, there are no known installations of oxidation catalysts on coal-fired power plant boilers.

   Several technical issues accompany the use of catalytic oxidation as a control for a coal-fired power plant boiler. For example, sulfur compounds in the flue gas tend to deactivate the catalyst at a rapid rate. Furthermore, in a coal-fired boiler, dust suspended in the exhaust gas tends to foul and poison the catalyst. Because of the catalyst fouling concern, the catalyst would have to be placed downstream of the particulate control device and the SO_2 control device. Even then, sulfur compounds and particulates remaining in the flue gas would tend to foul the catalyst.

   The need to place the catalyst downstream of the SO_2 and particulate control devices creates other problems--primarily dealing with flue gas temperature. The flue gas exiting the particulate control device (baghouse) would be approximately 180°F, while the catalyst requires a minimum temperature of approximately 500°F-600°F to oxidize CO to CO_2. The exhaust gases would have to be reheated to approximately 500°-600°F for the CO oxidation to occur. Reheating the exhaust would require oil - fired heaters, which would increase overall emissions of NO_x and PM_{10}.

   Finally, the conditions necessary to oxidize CO would also oxidize SO_2 to SO_3. It is estimated that as much as 30-50% of the SO_2 in the flue gas would oxidize to SO_3 as a result of the CO oxidation catalyst. SO_3 would react with moisture in the flue gas to form sulfuric acid mist in the atmosphere.

b. Thermal Oxidation - Thermal oxidation uses heat and oxygen to convert CO to CO_2. Because no catalyst is used in a thermal oxidizer, the temperature at which the conversion takes place is much higher. Temperatures above 1500°F are required to convert CO to CO_2.

   Particulate matter present in the coal-fired boiler exhaust gas would accumulate in the thermal oxidizer chamber and would plug and foul fans, ductwork, and other essential equipment. Therefore, as with catalytic oxidizers, thermal oxidizers must be located downstream of the particulate control device. The exhaust gas temperature at the baghouse outlet is typically approximately 180°F. To increase the exhaust temperature from 180°F to 1500°F requires a series of heat exchangers and a natural gas-fired furnace. Burning of additional fuel to heat the exhaust gas would increase overall emissions of NO_x, CO, and PM_{10}. The Department was unable to find any coal-fired power plants that use thermal oxidizers. Most thermal oxidation technology for stationary sources is utilized for the control of volatile organic compound emissions.

c. Proper Boiler Design and Operation - A properly designed and operated boiler effectively minimizes CO emissions. CO formation is minimized when the boiler temperature and excess oxygen availability are adequate for complete combustion. Minimizing CO emissions is in the economical best interest of the boiler operator because CO represents unutilized energy exiting the process.

   Proper boiler design and operation can minimize the generation of both CO and NO_x. The Department determined that a CO emission limit of 602.0 lb/hr (0.15 lb/MMBtu) constitutes BACT for the proposed boiler. Furthermore, the Department determined that proper boiler design and operation is necessary to maintain compliance with the CO emission limit established as part of this BACT analysis. Because of the technological difficulties associated with designing an oxidation catalyst for a coal-fired boiler, and because an oxidation catalyst system has not been used on a coal-fired power plant and is not commercially available, catalytic oxidation is deemed to be technically infeasible and was eliminated from further consideration in the BACT analysis. Furthermore, because of the technical issues (need to reheat gas and burn more fuel) associated with thermal oxidation and because thermal oxidizers have not been used on coal-fired power plants or any other stationary source applications of this magnitude, the use of a thermal oxidizer was eliminated from further consideration.

5. VOC Emissions

The rate at which VOCs are emitted depends on the combustion efficiency of the boiler. Controls that are designed to reduce NO_x emissions tend to increase VOC emissions and controls that tend to reduce CO emissions tend to reduce VOC emissions. Post-combustion catalytic oxidation and thermal oxidation would generally reduce VOC emissions, but neither of these control options is considered technically feasible because they have not been practically proven on a pulverized coal unit.

The only technically feasible control option for VOC control is proper design and operation. With proper design and operation, a pulverized coal boiler will provide all of the factors to facilitate complete VOC combustion, including extended residence time, consistent high temperatures in the combustion chamber, and continuous mixing of air and fuel. Proper boiler design and operation will minimize VOC emissions and limit the generation of NO_x. Also as part of the BACT determination, the Department determined that a VOC limit of 12.0 lb/hr (0.0030 lb/MMBtu) is appropriate.

6. Sulfuric Acid Mist Emissions

Sulfuric acid mist is one of the PSD pollutants listed in 40 CFR 52.21. Sulfuric acid mist is typically generated when sulfuric trioxide (SO_3) in the flue gas reacts with water to form sulfuric acid. The combustion of coal will result in the formation of sulfuric acid.

Four options were analyzed for the sulfuric acid mist control technology review. The four options are summarized below.

a. Dry FGD (Spray Dry Absorber) - Using a dry FGD system, SO_3 would react with sprayed lime in the absorber to form calcium sulfate. Because SO_3 is very reactive, approximately 90% of the SO_3 would be removed from the flue gas in the spray dry absorber and subsequent reactions in the fabric filter. The remaining 10% (5 ppm) of the SO_3 would be emitted to atmosphere and would react with water in atmosphere and precipitate out of the atmosphere as sulfuric acid.

b. Wet FGD - Using a wet FGD system, SO_3 would enter the wet scrubbers and react with the water to form micron sized sulfuric acid droplets. Because micron sized droplets can pass through the spray levels and the mist eliminator, the droplets can be emitted as sulfuric acid mist. Although some of the droplets would react with limestone in the wet scrubber, the size of the droplets would prevent the majority of the droplets from contacting the limestone. Approximately 25% of the sulfuric acid mist droplets would be captured by this system and approximately 75% (37.5 ppm) of the sulfuric acid mist droplets would be released to atmosphere from this system.

c. Wet FGD with WESP - While using Wet FGD, sulfuric acid mist can be further reduced by using a WESP downstream from the Wet FGD. The sulfuric acid mist would be removed from the flue gas stream as a condensable particulate in the

WESP. Using WESP in conjunction with wet FGD would reduce the sulfuric acid mist emissions by approximately 90%. The remaining 10% (5 ppm) would be emitted to atmosphere.

d. No Additional Controls - The base case would result in approximately 50 ppm of sulfuric acid mist.

Roundup Power proposed and the Department agrees that dry FGD constitutes BACT for sulfuric acid mist emissions. Not only is the use of dry FGD technology feasible, but dry FGD is required as part of the SO_2 BACT analysis and will be economically feasible.

B. Auxiliary Boilers

In addition to the coal-fired main boilers, the Roundup Power Project will have two oil-fired auxiliary boilers. The auxiliary boilers will generate steam for heating plant buildings and for start-up of the main boilers when both of the main units are shut down. Generally, operation of the auxiliary boilers will not be necessary when either of the main boilers is operating.

As proposed, the auxiliary boilers would be designed with low NO_x burners, and would be fired with low sulfur No. 2 fuel oil. This is an inherently clean fuel, with a maximum sulfur content of 0.05% and a maximum ash content of 0.25%. Emissions from the auxiliary boilers would also be minimized by limits on the annual hours of operation of the boilers. As stated above, the primary function of the auxiliary boilers is to provide steam for start-up and plant heating when both of the main boilers are shut down. Each of the main boilers is expected to have an average annual capacity factor of approximately 90%, so operation of the auxiliary boilers should be very infrequent.

In order to estimate maximum annual emissions from the auxiliary boilers, it was assumed that during some years the auxiliary boilers might need to operate as much as 3,300 hours/year (total for both boilers). This assumption is considered very conservative, because in most years the auxiliary boilers are expected to operate much less than 3,300 hours/year. Nevertheless, limiting the hours of operation to 3,300 hours/year will reduce the potential annual emissions from the auxiliary boilers by more than 81%.

The Department determined that the use of low NO_X burners and low sulfur No. 2 fuel oil, in conjunction with the requested hourly restriction (3300 hours per rolling 12-month period), constitutes BACT for the auxiliary boilers. In addition, the emissions of SO_2 are limited to 6.46 lb/hr, the emissions of NO_x are limited to 19.8 lb/hr, and the emissions of CO are limited to 4.12 lb/hr.

C. Backup Generator

The proposed Roundup Power facility will be equipped with one 1.6-MW emergency generator fired with low sulfur No. 2 fuel oil. As discussed above, low sulfur No. 2 fuel oil is an inherently clean fuel. Furthermore, the emergency generator would be used only during an interruption of the electrical power supply to the site and for short test periods. It is estimated that the emergency generator would be fired for a maximum of 200 hours per year.

The Department determined that the use of low sulfur No. 2 fuel oil, in conjunction with the requested hourly restriction (200 hours per rolling 12-month period), constitutes BACT for the emergency generator.

D. Material Handling Emission Sources - Particulate Emissions

The proposed Roundup Power facility would consist of numerous sources of particulate emissions (transfer points, fugitive sources, and storage piles). Control options for each of the sources have been analyzed to determine the best available control technology.

1. Transfer Points

Transfer points include railcar/truck loading and unloading, conveyor to conveyor drops, material transfers from reclaim hoppers to conveyors, and transfers from conveyors to storage silos. Particulate emissions would be generated as the material drops through the transfer point. The potential to generate particulate emissions at a transfer point is a function of the rate at which the material flows through the transfer point, the material's particle size, and the material's moisture content.

Based on EPA's emission factor for predicting particulate emissions from a transfer point (which factors in wind speed, material particle size distribution, and moisture content), potential emissions from a transfer point can be reduced by decreasing the speed at which the material is transferred or increasing the aggregate's moisture content by watering or chemical wetting agents. Transfer point emissions may be further reduced by enclosing the transfer operations within a structure and exhausting the structure through a particulate control device.

The Department determined that the use of a combination of dust suppression systems, enclosures, and baghouses to control particulate matter emissions from coal handling transfer points constitutes BACT. Furthermore, the Department determined that the lime needs to be handled/transferred using a pneumatic system and that a bin exhaust filter needs to be used on each of the two lime storage silos. Roundup Power will be required to ensure that all fly ash is transferred using a vacuum-pressure system. The Department also determined that all baghouses/bin vents used to control emissions from the material handling system need to be capable of maintaining a maximum outlet emission rate of 0.010 grain/dscf.

2. Fugitive Dust Sources

Fugitive particulate emissions from coal, lime, and fly ash handling can occur at several points in the storage cycle, including material loading onto a storage pile, disturbances by strong wind currents, and loadout from the pile. Based on AP-42 equations that predict the potential particulate emissions from an aggregate storage pile, the generation of fugitive dust from material handling is a function of the following variables:

a. Threshold Friction Velocity - Threshold friction velocity is a characteristic of the storage pile that relates to the wind speed necessary to remove dust particles from the storage pile. The higher the threshold friction velocity the higher the wind speed needed to generate dust. Threshold friction velocity is a function of the material's erosion potential, which in turn is a function of the material's size distribution and moisture content. Increasing the material's particle size or moisture content would decrease its erosion potential and increase the storage pile's threshold friction velocity.

b. Wind Speed - Wind speed at the face of the storage pile must exceed the threshold friction velocity in order to generate dust.

c. Frequency of Disturbance - Emissions generated by wind erosion are dependent on the frequency of disturbance of the erodible surface of the storage pile. Each time that a surface is disturbed, its erosion potential is restored. A disturbance is defined as an action that results in the exposure of fresh surface material. On a storage pile, this would occur whenever material is added to or removed from the old surface.

The potential for fugitive emissions from a storage pile can be reduced by reducing the material's erosion potential, reducing the wind speed at the face of the storage pile, and/or reducing the frequency of storage pile disturbances. Watering, or the use of chemical wetting agents, can reduce the erosion potential of a storage pile. Reducing the maximum wind speed that impacts the face of the storage pile can reduce wind erosion. Technologies that may feasibly reduce wind speed include enclosures and wind breaks around the storage pile.

Several control technologies may be used to reduce particulate emissions from material handling transfer points. Particulate matter control options considered for the Roundup Power Project include dust suppression systems, enclosed transfer points, pneumatic lines, and baghouse filters.

Spray dust suppression systems consist of a fine water mist that is sprayed onto the aggregate as it moves through the transfer point. The water mist effectively knocks down particulates before they are emitted to the atmosphere. Based on manufacturer studies and literature, it is predicted that a properly operating spray dust suppression system can reduce potential particulate emissions from a material transfer point by approximately 95%.

Locating transfer points within an enclosed building would also reduce particulate emissions. Dust generated from the transfer point would be contained within the building. Depending on air movement within the enclosure, and the material's particle size distribution, dust generated from the transfer point would either settle out in the enclosure or be emitted with the building's exhaust. If transfer operations within an enclosure are such that significant dust will be exhausted, a dust collection system (e.g., baghouse) can be used at the building's emission point to reduce particulate emissions. A baghouse can reduce particulate emissions from the transfer points by greater than 99.5% on a consistent basis, and can be designed to meet an outlet loading of 0.010 grain/dscf under all inlet loading conditions.

Separate material handling systems will be designed to handle lime and fly ash. Lime will be handled/transferred using a pneumatic system, and fly ash will be transferred using a vacuum/pressure system. A complete description of the proposed material handling systems, identifying the coal, lime, and fly ash transfer points, emission points, and control systems is included in Section 2 of the permit application.

The Department determined that dust suppression systems, enclosed transfer points, pneumatic lines, and baghouse filters constitute BACT for the fugitive dust sources.

3. Active Storage Piles

Totally enclosing the active storage pile is not practical because of the activity at the active storage pile (i.e., bulldozing and adding coal to the pile with a radial stacker). However, active coal storage piles have been located within coal storage sheds. Storage sheds are designed such that coal is delivered to the active storage pile by way of a conveyor system. Coal in the storage shed is funneled to the bottom of the shed where large rotary plows scrape the coal onto conveyors to be transported to the boilers. A storage shed would eliminate wind erosion from the active storage pile, however, particulates would still be generated by the rotary plows and from adding coal to the storage pile.

Particulates generated from the rotary plows and from adding coal to the active storage pile may be emitted with the storage shed's ventilation exhaust. It is estimated that total particulates from the active storage pile would be reduced by approximately 98% if the active storage pile were located within a storage shed.

Roundup Power proposed to control particulate emissions from the active storage pile by installing a wind fence and using dust suppression sprays on coal as it is added to the pile. The Department agrees that the use of such techniques constitutes BACT in this case. It is predicted that this combination of control strategies will reduce potential particulate emissions from the active storage pile by 98%.

4. Inactive Storage Pile

Several design and operational techniques exist to control fugitive emissions from an aggregate storage pile. The effectiveness of each control system would depend on the type of material stored, the size and shape of the pile, and how often the storage pile is disturbed. Fugitive emission control options considered for Roundup Power are described below.

Totally enclosing a material storage pile that is infrequently disturbed may be a technically feasible option to control fugitive emissions. It may be possible to construct a structure covering approximately 100,000 square feet to cover the inactive coal storage pile. The structure would have to be designed to allow coal to be added and removed from the pile. The most economical structure available to cover a storage pile would likely be an air-inflated building. Although enclosing the inactive storage pile may be technically feasible, the Department is not aware of any pulverized coal facilities with covered inactive storage piles, and technical issues may arise which would preclude covering the entire storage pile. For example, heat generated within the storage pile may not be effectively dissipated thus creating a fire hazard.

Enclosing the inactive storage pile would reduce wind speeds at the surface of the storage pile, essentially eliminating emissions generated from wind erosion. Particulates would only be generated when the storage pile is disturbed (e.g., material is either added to or removed from the pile). Particulates generated when the pile is disturbed may be emitted to the atmosphere with the enclosure's exhaust system. Assuming that particulates would only be generated when the inactive storage pile is disturbed, it is predicted that totally enclosing the inactive storage pile would reduce potential particulate emissions by approximately 99.5%.

A wind fence may be a feasible option to reduce the wind speed at the surface of a storage pile and thus reduce particulate emissions. Wind tunnels and field experiments have shown that windbreaks produce large areas of reduced wind speed in their line. A properly designed windbreak placed upwind of an oval, flat-topped storage pile can produce wind speed reduction factors of 20 - 60% over the surface of the pile. To be effective, the windbreak should be at least as high as the pile and as long as the pile base. Windbreaks of height and/or length less than that of the pile are less effective. Based on published literature, and AP-42 emission factors, it is predicted that a windbreak would reduce potential particulate emissions by 90% for each wind event. Reducing the windspeed reduces the number of events in which the coal threshold friction velocity is exceeded. Therefore, the number of emission events per year is reduced and the annual emission reduction is 98%.

Dust suppression sprays can be used on storage piles to reduce particulate emissions. Dust suppression sprays can consist of a water spray or water mixed with surfactants to increase wetting and/or produce a residual crust over the storage pile. Dust suppression sprays reduce the material's erosion potential, thus increasing the threshold friction velocity. Therefore, a higher wind speed would be required to generate dust from the storage pile. Compacting the storage pile can further reduce the pile's erosion potential. It is estimated that treating material storage piles which are not frequently disturbed (e.g., the inactive coal pile) with compaction and a dust suppression spray can reduce total particulate emissions from aggregate storage operations by up to 90%.

Using a dust suppression spray consisting of water and/or a surfactant to increase wetting on the active storage pile would not be as effective, and would require more frequent application of the suppressant because disturbing the pile would restore its erosion potential. It is projected that application of a dust suppression spray to material being added to the active storage pile will reduce potential fugitive emissions from the pile by 80%.

Roundup Power is proposing, and the Department agrees, that particulate emissions from the inactive storage pile should be controlled by installing a wind fence and using dust suppression sprays and pile compaction. It is predicted that this combination of control strategies will reduce potential particulate emissions from the inactive storage pile by 98%.

The control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

IV. Emission Inventory

Source	PM_{10} (tpy)	SO_2 (tpy)	NO_x (tpy)	VOC (tpy)	CO (tpy)	HAPs (tpy)	Pb (tpy)
Main Boiler #1 (MP-1)	245.5	1964.2	1145.7	49.1	2455.2	45.09	0.10
Main Boiler #2 (MP-2)	245.5	1964.2	1145.7	49.1	2455.2	45.09	0.10
Auxiliary Boiler #1 (AB-1)	1.36	5.34	16.32	0.17	3.40	0.15	0.00
Auxiliary Boiler #2 (AB-2)	1.36	5.34	16.32	0.17	3.40	0.15	0.00
Backup Generator (BG-1)	0.05	0.08	4.42	0.10	0.10	0.00	0.00
Coal Handling	8.29	---	---	---	---	---	---
Lime Handling	1.06	---	---	---	---	---	---
Fly Ash Handling	5.26	---	---	---	---	---	---
Totals	508.4	3939.1	2328.5	98.64	4917.3	90.48	0.20

Main Power Boiler #1 (MP-1)

Fuel: Pulverized bituminous coal
Nominal Gross Plant Output = 390,100 kW
Nominal Net Plant Output = 350,172 kW
Maximum Short Term Primary Fuel Feed Rate = 202 ton/hr
Maximum Short Term Heat Input to Boiler = 4013 MMBtu/hr
Maximum Long Term Primary Fuel Feed Rate = 188 ton/hr
Maximum Long Term Heat Input to Boiler = 3737 MMBtu/hr
Sorbent Feed Rate = 10,332 lb/hr (45,255 ton/yr)
Annual Capacity Factor = 100% per year

PM_{10} Emissions

Emission Factor (uncontrolled) = 8.16 lb/MMBtu
Emission Factor (controlled) = 0.015 lb/MMBtu (permit condition)
Calculations: 0.015 lb/MMBtu * 4013 MMBtu/hr = 60.2 lb/hr (short-term limit)
0.015 lb/MMBtu * 3737 MMBtu/hr = 56.1 lb/hr (long-term average value)
56.1 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 245.5 ton/yr (annual limit)

SO_x Emissions

Emission Factor (uncontrolled) = 2.17 lb/MMBtu
Calculations: 0.15 lb/MMBtu * 4013 MMBtu/hr = 602.0 lb/hr (1-hr limit)
0.12 lb/MMBtu * 4013 MMBtu/hr = 481.6 lb/hr (24-hr limit)
0.12 lb/MMBtu*3737 MMBtu/hr*8760 hr/yr*0.0005 ton/lb=1964.2 ton/yr (annual limit)

NO_x Emissions

Emission Factor (uncontrolled) = 31 lb/ton (AP-42, Table 1.1-3, 9/98)
Emission Factor (unc.) = 31 lb/ton * 188 ton/hr * 1hr/3737 MMBtu = 1.56 lb/MMBtu
Emission Factor (controlled) = 0.07 lb/MMBtu (permit condition)
Calculation: 0.10 lb/MMBtu * 4013 MMBtu/hr = 401.3 lb/hr (1-hr limit)
0.07 lb/MMBtu * 4013 MMBtu/hr = 280.9 lb/hr (24-hr limit)
0.07 lb/MMBtu*3737 MMBtu/hr*8760 hr/yr*0.0005 ton/lb=1145.8 ton/yr (annual limit)

VOC Emissions

Emission Factor (uncontrolled) = 0.0030 lb/MMBtu (permit condition)
Calculation: 0.0030 lb/MMBtu * 3737 MMBtu/hr = 11.21 lb/hr (long term average value)
0.0030 lb/MMBtu * 4013 MMBtu/hr = 12.0 lb/hr (short term limit)
11.21 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 49.1 ton/yr (annual limit)

CO Emissions

Emission Factor (uncontrolled) = 0.15 lb/MMBtu (permit condition)
Calculation: 0.15 lb/MMBtu * 3737 MMBtu/hr = 560.55 lb/hr (long term average value)
0.15 lb/MMBtu * 4013 MMBtu/hr = 601.9 lb/hr (short term limit)
560.55 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 2455.2 ton/yr (annual limit)

HAP Emissions

Total HAP emissions were determined for "unwashed coal." A summary of the calculations for the HAP emissions is contained in Permit Application #3182-00 (in Appendix B). The total HAP emissions are the sum of the total emissions from several tables in the appendix. HAPs = 45.09 ton/yr

Main Power Boiler #2 (MP-2)

Fuel: Pulverized bituminous coal
Nominal Gross Plant Output = 390,100 kW
Nominal Net Plant Output = 350,172 kW
Maximum Short Term Primary Fuel Feed Rate = 202 ton/hr
Maximum Short Term Heat Input to Boiler = 4013 MMBtu/hr
Maximum Long Term Primary Fuel Feed Rate = 188 ton/hr
Maximum Long Term Heat Input to Boiler = 3737 MMBtu/hr
Sorbent Feed Rate = 10,332 lb/hr (45,255 ton/yr)
Annual Capacity Factor = 100% per year

PM_{10} Emissions

Emission Factor (uncontrolled) = 8.16 lb/MMBtu
Emission Factor (controlled) = 0.015 lb/MMBtu (permit condition)
Calculations: 0.015 lb/MMBtu * 4013 MMBtu/hr = 60.2 lb/hr (short-term limit)
0.015 lb/MMBtu * 3737 MMBtu/hr = 56.1 lb/hr (long-term average value)
56.1 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 245.5 ton/yr (annual limit)

SO_x Emissions

Emission Factor (uncontrolled) = 2.17 lb/MMBtu
Calculations: 0.15 lb/MMBtu * 4013 MMBtu/hr = 602.0 lb/hr (1-hr limit)
0.12 lb/MMBtu * 4013 MMBtu/hr = 481.6 lb/hr (24-hr limit)
0.12 lb/MMBtu*3737 MMBtu/hr*8760 hr/yr*0.0005 ton/lb=1964.2 ton/yr (annual limit)

NO_x Emissions

Emission Factor (uncontrolled) = 31 lb/ton (AP-42, Table 1.1-3, 9/98)
Emission Factor (unc.) = 31 lb/ton * 188 ton/hr * 1hr/3737 MMBtu = 1.56 lb/MMBtu
Emission Factor (controlled) = 0.07 lb/MMBtu (permit condition)
Calculation: 0.10 lb/MMBtu * 4013 MMBtu/hr = 401.3 lb/hr (1-hr limit)
0.07 lb/MMBtu * 4013 MMBtu/hr = 280.9 lb/hr (24-hr limit)
0.07 lb/MMBtu*3737 MMBtu/hr*8760 hr/yr*0.0005 ton/lb=1145.8 ton/yr (annual limit)

VOC Emissions

Emission Factor (uncontrolled) = 0.0030 lb/MMBtu (permit condition)

Calculation: 0.0030 lb/MMBtu * 3737 MMBtu/hr = 11.21 lb/hr (long term average value)

0.0030 lb/MMBtu * 4013 MMBtu/hr = 12.0 lb/hr (short term limit)

11.21 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 49.1 ton/yr (annual limit)

CO Emissions

Emission Factor (uncontrolled) = 0.15 lb/MMBtu (permit condition)

Calculation: 0.15 lb/MMBtu * 3737 MMBtu/hr = 560.55 lb/hr (long term average value)

0.15 lb/MMBtu * 4013 MMBtu/hr = 601.9 lb/hr (short term limit)

560.55 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 2455.2 ton/yr (annual limit)

HAP Emissions

Total HAP emissions were determined for "unwashed coal." A summary of the calculations for the HAP emissions is contained in Permit Application #3182-00 (in Appendix B). The total HAP emissions are the sum of the total emissions from several tables in the appendix. HAPs = 45.09 ton/yr

Auxiliary Boiler #1 (AB-1)

Fuel = No.2 Fuel Oil

Boiler Heat Input with Margin = 117 MMBtu/hr

Fuel Consumption = 6014 lb/hr

Total Fuel Consumption = 824 gal/hr

Annual Fuel Consumption = 1,359,600 gal

Hours of operation = 3300 hours per year combined (≅1650 hours)

Sulfur in Fuel = 0.05%

PM_{10} Emissions

Emission Factor = 2 lb/1000 gal (AP-42, Table 1.3-1, 9/98)

Calculation: (2/1000) lb/gal * 824 gal/hr = 1.646 lb/hr

1.646 lb/hr * 1650 hr/yr * 0.0005 ton/lb = 1.36 ton/yr

SO_x Emissions

Emission Factor = 157*S lb/1000 gal (AP-42, Table 1.3-1, 9/98)

Calculation: (157(0.05)/1000) lb/gal * 824 gal/hr = 6.468 lb/hr

6.468 lb/hr * 1650 hr/yr * 0.0005 ton/lb = 5.34 ton/yr

NO_x Emissions

Emission Factor = 24 lb/1000 gal (AP-42, Table 1.3-1, 9/98)

Calculation: (24/1000) lb/gal * 824 gal/hr = 19.78 lb/hr

19.78 lb/hr * 1650 hr/yr * 0.0005 ton/lb = 16.32 ton/yr

VOC Emissions

Emission Factor = 0.252 lb/1000 gal (AP-42, Table 1.3-1, 9/98)

Calculation: (0.252/1000) lb/gal * 824 gal/hr = 0.208 lb/hr

0.208 lb/hr * 1650 hr/yr * 0.0005 ton/lb = 0.17 ton/yr

CO Emissions

Emission Factor = 5 lb/1000 gal (AP-42, Table 1.3-1, 9/98)

Calculation: (5/1000) lb/gal * 824 gal/hr = 4.12 lb/hr

4.12 lb/hr * 1650 hr/yr * 0.0005 ton/lb = 3.40 ton/yr

HAP Emissions

Emission Factors (AP-42, Table 3.4-3, Table 3.4-4, 10/96)

Calculation: See Permit Application #3182-00, Appendix B = 0.15 ton/yr

Auxiliary Boiler #2 (AB-2)
Fuel = No.2 Fuel Oil
Boiler Heat Input with Margin = 117 MMBtu/hr
Fuel Consumption = 6014 lb/hr
Total Fuel Consumption = 824 gal/hr
Annual Fuel Consumption = 1,359,600 gal/yr per boiler
Hours of operation = 3300 hours per year combined (≅1650 hours)
Sulfur in Fuel = 0.05%

PM_{10} Emissions
Emission Factor = 2 lb/1000 gal (AP-42, Table 1.3-1, 9/98)
Calculation: (2/1000) lb/gal * 824 gal/hr = 1.648 lb/hr
1.648 lb/hr * 1650 hr/yr * 0.0005 ton/lb = 1.36 ton/yr

SO_x Emissions
Emission Factor = 157*S lb/1000 gal (AP-42, Table 1.3-1, 9/98)
Calculation: (157(0.05)/1000) lb/gal * 824 gal/hr = 6.468 lb/hr
6.468 lb/hr * 1650 hr/yr * 0.0005 ton/lb = 5.34 ton/yr

NO_x Emissions
Emission Factor = 24 lb/1000 gal (AP-42, Table 1.3-1, 9/98)
Calculation: (24/1000) lb/gal * 824 gal/hr = 19.78 lb/hr
19.78 lb/hr * 1650 hr/yr * 0.0005 ton/lb = 16.32 ton/yr

VOC Emissions
Emission Factor = 0.252 lb/1000 gal (AP-42, Table 1.3-1, 9/98)
Calculation: (0.252/1000) lb/gal * 824 gal/hr = 0.208 lb/hr
0.208 lb/hr * 1650 hr/yr * 0.0005 ton/lb = 0.17 ton/yr

CO Emissions
Emission Factor = 5 lb/1000 gal (AP-42, Table 1.3-1, 9/98)
Calculation: (5/1000) lb/gal * 824 gal/hr = 4.12 lb/hr
4.12 lb/hr * 1650 hr/yr * 0.0005 ton/lb = 3.40 ton/yr

HAP Emissions
Emission Factors (AP-42, Table 3.4-3, Table 3.4-4, 10/96)
Calculation: See Permit Application #3182-00, Appendix B = 0.15 ton/yr

Backup Generator (BG-1)
Fuel = No.2 Fuel Oil
Size = 2336.2 Hp
Max. Sulfur in Fuel = 0.05%
Fuel Consumption = 111.5 gal/hr
Hours of operation = 200 hours per year

PM_{10} Emissions
Emission Factor = 0.52 lb/hr (Manufacturer's Data)
Calculation: 0.52 lb/hr * 200 hr/yr * 0.0005 ton/lb = 0.05 ton/yr

SO_x Emissions
Emission Factor = 0.00355 lb/gal (Mass Balance - Allowable Sulfur in Fuel)
Calculation: 0.00355 lb/gal * 111.5 gal/hr * 2 lb SO_2/lb S = 0.7917 lb/hr
0.7917 lb/hr * 200 hr/yr * 0.0005 tons/lb = 0.08 ton/yr

NO_x Emissions

Emission Factor = 44.22 lb/hr (Manufacturer's Data)

Calculation: 44.22 lb/hr * 200 hr/yr * 0.0005 ton/lb = 4.42 ton/yr

VOC Emissions

Emission Factor = 0.98 lb/hr (Manufacturer's Data)

Calculation: 0.98 lb/hr * 200 hr/yr * 0.0005 ton/lb = 0.10 ton/yr

CO Emissions

Emission Factor = 0.95 lb/hr (Manufacturer's Data)

Calculation: 0.95 lb/hr * 200 hr/yr * 0.0005 ton/lb = 0.10 ton/yr

HAP Emissions

Emission Factors (AP-42, Table 3.4-3, Table 3.4-4, 10/96)

Calculation: See Permit Application #3182-00, Appendix B = 0.00 ton/yr

V. Existing Air Quality

As part of complying with the PSD program requirements, Roundup Power was required to conduct on-site pre-monitoring for PM_{10} and SO_2, because air modeling showed the concentrations of these pollutants to exceed the levels identified in ARM 17.8.818(7). Roundup Power requested to use, and the Department agreed to accept, ambient PM_{10} data that was collected by Meridian Minerals Company from March 1989 through March 1992. The Department agreed that this data was representative of the year preceding the permit application because there have been no significant new sources of PM_{10} added to the area or removed from the area. The measured PM_{10} values yielded an annual average PM_{10} concentration of 9 $\mu g/m^3$, and the maximum measured 24-hour concentration was 53 $\mu g/m^3$ (compared to standards of 50 $\mu g/m^3$ for the annual average, and 150 $\mu g/m^3$ for the 24-hour average).

Ambient monitoring was conducted by Roundup Power to measure the concentration of SO_x in the project area. Roundup Power began collecting ambient SO_x data on January 1, 2002. Based upon the ambient SO_x data collected, the amount of SO_2 in the immediate area of the project facility is relatively low (highest measured 1-hour concentration was 16 ppb, highest measured 3-hour concentration was 10 ppb, highest measured 24-hour concentration was 3 ppb). Because the measured concentrations of SO_x were relatively low, the Department decided that 4 months of pre-monitoring data would satisfy the requirements of ARM 17.8.822. All of the measured concentrations were very low in comparison to the applicable Montana and Federal ambient air quality standards.

Roundup Power also elected to conduct ambient monitoring to measure the concentration of NO_2 in the project area. Roundup Power began collecting ambient NO_2 data on January 1, 2002. Based upon the pre-monitoring data collected, the amount of NO_2 in the immediate area of the project facility is relatively low (highest measured 1-hour concentration was 8 ppb for NO_2). The measured concentrations were very low in comparison to the applicable 1-hour Montana ambient air quality standards.

Baseline monitoring was not conducted for any other air pollutants. The proposed project area is considered to be in attainment of all air quality standards.

VI. Ambient Air Impact Analysis

The Department determined, based on ambient air modeling, that the air quality impacts from this permitting action will be mostly minor. A more detailed description of the ambient air quality impacts is contained in the permit application and the final environmental impact statement (EIS). The Department believes the proposed project will not cause or contribute to a violation of any ambient air quality standard.

VII. Visibility Impact Analysis

CALPUFF modeling was conducted by Roundup Power and the FLMs to determine the impacts from this facility on the visibility of the nearby federal mandatory Class I areas. Based upon the information contained in the initial permit application and the information contained in the preliminary determination for Permit #3182-00, the FLMs submitted correspondence indicating their belief that Roundup Power would lead to an adverse impact on visibility in nearby Class I areas. However, after that submittal, Roundup Power submitted an additional case-by-case analysis for the days of modeled impact. After determining that the new data indicates an adverse impact will not result from the Roundup Power facility, the FLMs withdrew their determination that an adverse impact would result from Roundup Power.

VIII. Taking or Damaging Implication Analysis

As required by 2-10-105, MCA, the Department conducted a private property taking and damaging assessment and determined there are no taking or damaging implications.

IX. Environmental Assessment

The final EIS for this project was issued by the Department on January 10, 2003.

Permit Analysis Prepared By: Dan Walsh
Date: 08/08/02
Revised: 01/10/03